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A STUDY OF THE PIPELINE

LEAK DETECTION TECHNOLOGY

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A STUDY OF THE PIPELINE LEAK DETECTION TECHNOLOGY

by

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TABLE OF CONTENTS

SECTION	TITLE
1.0	INTRODUCTION
2.0	SCOPE OF WORK
3.0	DEFINITION OF LEAKS
4.0	CAUSES OF LEAKS
5.0	LEAK INSPECTION METHOD
	5.1 Pressure Test
	5.2 Ultrasonic Technique
	5.3 Magnetic Flux
	5.4 Acoustic Emission Technique
	5.5 Visual Inspection
	5.6 Oil Spill Detection at Marine Terminals
6.0	LEAK DETECTION METHOD
	6.1 Sonic Leak Detection
	6.2 Passive Acoustic Array
	6.3 Volumetric Method

TABLE OF CONTENTS (cont'd)

6.4 Negative Pressure Surge Method

6.5 Mathematical Modelling

7.0 CONCLUSIONS

8.0 RECOMMENDATIONS

APPENDICES

APPENDIX I THEORY OF MATHEMATICAL MODELLING

APPENDIX II PIPELINE PROFILE AND FLUID PROPERTIES

APPENDIX III ADDITIONAL BENEFITS OFMATHEMATICAL MODELLING

REFERENCES

LIST OF FIGURES

FIGURE	DESCRIPTION	PAGE
5.1	Reflection and Refraction of an Ultrasonic Wave	
5.2	Ultrasonic Wave Action	
5.3	Magnetic Flux Leakage	
5.4	Acoustic Emission Analysis System	
5.5	Geometry of a Bistatic Sensor	
6.1	Leakage Signal	
6.2	Elastic Wave Propagation in the Earth	
6.3	Flow During Pump Stop and Start	
6.4	Event of Figure 6.3 as Felt at the Upstream Pump	
6.5	Rate of Pressure Drop Device	
6.6	Rate of Flow Device	
6.7	Pressure Wave Propagation after a Leak	
6.8	Pressure Profiles Before and After the Leak	
6.9	SCADA and Model Interface	
6.10	Leak Location	
6.11	Range of Leak Location	
6.12	Imbalance Curve (1.0% Leak)	
6.13	Imbalance Curve (10.0% Leak)	

LIST OF TABLES

TABLE	DESCRIPTION	PAGE
5.1	Inspection System Capability	
6.1	Pressure vs. Time vs. Distance From The Leak (Oil Pipeline)	
6.2	Leak Size vs. Leak Location vs. Time	
6.3	Measurement Spacing Sensitivity Analysis	
6.4	Leak Location vs. Instrument Accuracy	
6.5	Hole Size vs. Leak Flow Rate	
6.6	Pressure vs. Time vs. Distance From The Leak (Rupture in a Gas Line)	
6.7	Pressure/Flow vs. Time	
6.8	Pressure vs. Time vs. Distance from The Leak (Gas Pipeline)	

LIST OF SYMBOLS

SYMBOL	DESCRIPTION
A	Pipe Cross-sectional Area
Am	Amplitude of the Transient Pressure Wave
a	Acoustic Velocity
C	Calibration Constant
D	Pipe Inside Diameter
Do	Pipe Outside Diameter
d	Distance to the Leak or Defect
d_l	Diameter of the Leak
dm	Diameter of the Monitored Line
dt	Diameter of the Tap
d/s	Downstream
E	Pipe Elastic Modulus
f	Darcy Friction Factor
g	Acceleration of Gravity
h	Elevation
K	Bulk Modulus
L	Length Between Two Measurement Points
M	Mass
P	Pressure
Pc	Pressure Constant
T	Temperature
t	Time
u/s	Upstream
V	Velocity of the Fluid

LIST OF SYMBOLS (cont'd)

wt	Pipe Wall Thickness
X	Distance
Δ M	Change in Mass
Δ P	Change in Pressure
Δ T	Total Temperature Change Over Pipeline Segment
Δ Tc	Temperature Change due to Conduction/Convection
Δ Te	Temperature Change due to Elevation Change
Δ Tf	Temperature Change due to Isenthalpic Expansion
Δ t	Time Step or Difference
Δ V	Volume Change
Δ X	Distance Step
α	Coefficient of Expansion of Steel
β	Coefficient of Expansion of Water
γ	Thermal Expansion Coefficient
ρ	Density
μ	Poisson's Ratio

1.0 INTRODUCTION

In this report, several state-of-the-art and common-use leak detection techniques are critically reviewed, especially for their applications to the pipeline systems in the Arctic and offshore. The techniques have been outlined mostly from published articles. A few techniques, which are proprietary company information, have not been elaborated on in this study.

In all cases, the general principle as well as the advantages/disadvantages are presented. Only the technical aspects, not economic, are taken into consideration. While reasonable efforts have been made by COV-CAN Control Systems Ltd., to present a complete overview of the subject matter, it may be necessary to seek more detailed information on each subject from specialized published papers or from equipment manufacturers.

Although this report does not pursue "the solution", the final chapter looks at some possible ways with which the central issue can be resolved. It is the intent of this study to lay the ground work to develop an optimum methodology in protecting the Arctic and offshore environment.

2.0 SCOPE OF WORK

COV-CAN Control Systems Ltd. has been contracted by the Department of the Environment to evaluate current leak detection capability for Arctic and Offshore pipelines. Presented here is the Scope of Work undertaken by COV-CAN.

Specific tasks outlined below are structured in such a way as to allow achievement for the following study objectives:

- Review the published data and information relevant to leak detection problems;

- Provide a detailed description of physical phenomena occurring during leaks of different magnitude for both gas and liquid lines;

- Provide a description of variation of different measurable parameters in the pipeline from the on-set of the leak to its eventual detection and location (if applicable);

- Describe how specific variation of measurable parameters are used to detect leaks in the leak detection methods applied by industry and specifically in:

  - Volume comparisons;

- Pressure variation with flow rate and volume comparisons and related mathematical models;
- Pressure pattern analysis;
- Acoustic monitors; and
- Combination of any of the above methods.

- Define the threshold magnitude of the leak required to generate sufficient magnitude of variation of the measured parameter or parameters for the specific leak detection method;

- Define the limitation and range of the applicability of each of the existing leak detection methods;

- Identify potential areas of improvements or enhancements to the existing methods of leak detection;

Summarize the results of the study in such a form that will allow for drawing and supporting the following conclusions and/or recommendations:

- Identify the most appropriate leak detection methods as a function of the size of the line, fluid transported, location of the line and magnitudes of leaks to be detected.

- Provide recommendation on type and location of measurement devices that could enhance the performance and reliability of leak detection methods described above;

- Provide recommendations on enhancement to the Supervisory Control and Data Acquisition systems that will allow for enhancements of the performance and reliability of the existing leak detection methods and introduction of the new and more accurate or more reliable methods.

3.0 DEFINITION OF LEAK

In this report, we basically adopt the definition of leaks expressed in "Petroleum Pipeline Leak Detection Study" [1]: incipient leaks and actual leaks.

Incipient leaks are those that are just about to occur and might soon result in a pipeline leak. Since incipient leaks can be discovered by inspecting the pipeline before it actually appears, detection methods of such leaks are called inspection methods, by which the integrity of the pipeline system is checked.

If fluid is leaking out of the pipeline system, the process is an actual leak. Detection methods of actual leaks are called leak detection methods, by which fluid leakage is detected.

Some inspection methods such as pressure testing and visual inspection can be applied as a leak detection method if a leak happens to appear during the test period.

4.0 CAUSES OF LEAKS

Since most leaks result from defects in the pipeline, it is desirable to understand the reasons for such failures. Pipe defects fall into the following types:

Manufacturing Defects

Manufacturing defects mostly result from physical damage done during pipe fabrication or welding. Such defects can be discovered and eliminated by means of visual inspection, hydrostatic testing and non-destructive testing (NDT) such as ultrasonic testing.

Defects Which Arise During Construction of Pipeline

Welding of pipes and pipe-laying operations may cause dents and buckles as well as improper fusion between pipes. This type of defect can be found and removed by visual inspection, X-Ray inspection and pressure testing prior to operation of the pipeline.

Defects Which Arise During Life of Pipeline

During the life of a pipeline, several factors can contribute to failures either separately or concurrently. The factors include:

External Corrosion

Pipeline corrosion, external and internal, is a major cause of defects. External corrosion in the buried pipeline poses a problem unique in the Arctic, because in addition to the normal corrosion process[2],

- Pipelines can be subject to corrosion due to telluric currents, which are electrical currents induced by changing magnetic field in the earth and oceans;

- Intermittent frozen and unfrozen zones become cathodic and anodic. Under the conditions, pipelines can be subject to external corrosion.

Offshore pipelines are also subject to external corrorion due to telluric currents and defects in corrosion coating[3].

Internal Corrosion

Internal corrosion is caused either by the corrosive action by pipeline fluids or by erosive-corrosive action of fluid and sand. If brine water and produced sands could enter the pipeline without being removed, erosion-corrosion could be a severe problem in some offshore lines[4]. Stress corrosion cracking is typically not severe in the Arctic pipelines, because flowing fluid at low temperature does not stimulate

cracking[5]. In such remote areas, stray current corrosion is also not a major concern.

Mechanical Damage

A large percentage of pipeline damage belongs to this type. Ships and other equipment may accidentally cause damage to offshore pipelines.

Geotechnical Instability

Thaw settlement stresses may cause pipeline bending and possible failure in the Arctic[6]. Mud slides can damage offshore lines.

Defects Statistics

These statistics are quoted from Oilweek[7].

"A tabulation of assigned causes of failure, based on technical investigation, showed 54% were due to materials defects and only 32% to outside forces. Of the outside forces, 18% of the total of all causes, were due to structural damage from terrain or thermal loading, while 14% were due to mechanical damage. The materials defects include hard spots, girth welds, stress corrosion cracking, pipe defects and miscellaneous, in that order. 14% of the total were caused by corrosion. Large diameter pipelines seem less susceptible than other lines. The

NEB tabulation of 368 incidents showed 24% due to corrosion, 27% to material defects, and 26% due to defective piping and equipment."

5.0 LEAK INSPECTION METHOD

5.1 Pressure Test (Hydrostatic and Pneumatic Test)

To assess the structural integrity of a pipeline, hydrostatic or pneumatic testing is often conducted for new and operating pipelines. The pipelines are tested with high pressure according to Canadian Pipeline Safety Standards. (Refer to Z184-M1983 for gas and Z183-M1982 for oil, published by Canadian Standards Association). The standards dictate the test pressure and test medium. In order to evaluate the need for the testing of the existing lines, the following considerations should be taken into account:

i) Requirements for the line service;
ii) Age of the line;
iii) Leak history; and
iv) Exposure to environment.

For pressure testing, the pipeline is divided into shorter segments, usually in the range of 15 to 60 km depending on elevation, code requirements, test medium and its availability. Each segment is filled with a test medium (water for hydrostatic and air for pneumatic test), while the fill medium is being accurately metered. The segment with the fill medium is maintained for about a day at a high pressure, which is constantly monitored with accurate pressure gages or dead

weight testers. If the pressure holds, it is assumed that the line is leak-free.

Since the line pressure varies with temperature, the temperature effect should be correctly taken into account during the test period. This problem is very important in the Arctic environment where temperature could change drastically in a short time or the soil surrounding the pipe can be frozen quickly[8].

The temperature effects on pressure and volume is shown below. The volume of water to fill a test section of the pipeline is simply the volume of the cylinder, with no additional pressure exerted on the section. To increment the internal pressure of the pipe section, however, additional volume of water should be pumped into the test section. The pressure and volume relationship is given by[9]:

$$\Delta P = \frac{\Delta V}{V\left[\frac{D_o}{Ewt}(1-\mu^2) + \frac{1}{K}\right]}$$

where:

ΔP = pressure increment due to added volume ΔV (kPa)

ΔV = volume increment in the pipe section

D_o = pipe outside diameter (mm)

wt = pipe wall thickness (mm)

E = pipe elastic modulus (kPa)

K = Water bulk modulus (kPa)

μ = Poisson's ratio

The incremental volume due to temperature change is given by:

$$\frac{\Delta V}{V} = \beta - 2\alpha$$

where:

α = coefficient of expansion of steel

β = coefficient of expansion of water

$= (-64.268 + 17.0105T - 0.20369T^2 + 0.0016048T^3) \times 10^{-6}$

T = water temperature (^{o}C)

From the above two equations, we have a relationship between the pressure and temperature:

$$\Delta p = \frac{\beta - 2\alpha}{\frac{D}{Ewt}(1-\mu^2) + \frac{1}{K}}$$

Typically, 1 ^{o}C drop in temperature results in about 180 kPa drop in pressure.

When a section of an operating pipeline using the transport medium is tested at a pressure above normal operating pressure, it is called a dynamic pressure testing (stress cycling method called by Munk and Parry, Refer to 6.4). The purpose of this

test is not to accommodate an increase in operating pressure level, but to qualify the pressure and liquid containment capability of the existing pipeline system.

The pressure test is widely accepted for testing structural integrity of new lines. In Europe, this test method is quite popular for operating lines. The test procedure is relatively simple and well understood. The method is also known to be very sensitive in detecting extremely small leaks, whose sensitivity is in the order of 0.1 M^3 per hour.

However, there is some concern about the effect of a pressure on the growth of defects that remain in the line after the test. Currently, it is not known conclusively whether a pressure test will accelerate growth of existing defects or if existing defects start to grow sooner after the test than they would have if the test had not been done[10].

Pneumatic vs. Hydrostatic Test[11]

Under National Energy Board pipeline regulations, the pipeline must be tested with water under high pressure, unless adverse weather conditions or water availability makes a hydrostatic test unreasonable. In the Arctic, there are several problems associated with the hydrostatic test:

1) Weather conditions in winter is unfavorably severe;

2) Water sources may be a problem especially during the winter test period. Also, water disposal after the test could impact on the Arctic environment;

3) If methanol should be added to water, the mixed test medium could be environmentally damaging;

4) The right-of-way during the summer months is mostly inaccessible.

Although the hydrostatic test is generally preferred, pneumatic testing of pipelines using air is an approved test method particularly in remote areas where water shortage is a problem and during winter construction. The pneumatic test is environmentally least risky and economically least costly, compared to various forms of hydrostatic tests. The test section of the pneumatic test can be longer than that of the hydrostatic test. In addition, the air test method is not subject to freezing of the fill medium, so that it is operational both in summer and in winter.

On the other hand, the pneumatic test requires a lengthy time to fill and test and increases the horsepower requirements for a given throughput. Potentially, it has higher risks of pipe damage and personnel injury. Since the pipe is tested under the mill test pressure, potential leaks may not be discovered. Another disadvantage is that there is virtually no available test data or actual experience of air testing in the Arctic.

Selection of test media and methods in the Arctic depends on the various constraints and considerations:

i) Least environmental impact;

ii) Availability and disposal of the test medium;

iii) Accessibility of the right-of-way; and

iv) Terrain types and thaw depths.

Advantages and Disadvantages

The main advantage of the pressure test is to provide good incipient failure detection. In addition, its leak detectability is so sensitive that a pin hole size leak can be detected.

However, there are several disadvantages to the method especially on the operational pipelines in the Arctic:

1) The method requires removal of the pipeline from service, so that it is very costly and inconvenient to conduct tests on operational lines;

2) Since it cannot locate the leak site, a leak location method is additionally needed if a leak is detected;

3) Since the method requires temperature stabilization for a long period of time, it requires extra precaution and it may be difficult to conduct the test in the Arctic;

4) Accessibility during the summer months can be a major problem in the Arctic. If water is selected as a test medium, its availability and disposal pose other problems in the Arctic.

5) Damage could occur on the pipeline beyond the source of the failure. If a line break takes place, it could be a destructive test;

6) The testing checks the pipeline integrity at the time of testing only. Non-critical cracks may withstand the pressure at the time of testing without being noticed;

7) The cyclic pressure conditions introduced during a test may cause an acceleration in crack growth.

5.2 Ultrasonic Inspection Technique

Ultrasonic inspection techniques are often used to detect pipe surface defects and pipe welds, and serves as standard procedures in inspecting manufactured pipes as well as operational pipelines.

The technique utilizes high frequency mechanical vibrations, whose frequencies range between 1 MHz and 25 MHz. The ultrasonic wave propagates in a longitudinal wave and a transverse wave. The transverse wave is a shear wave, and primarily used to detect cracks in pipes. The longitudinal wave is a compressional wave and is mainly used to measure the pipe wall thickness.

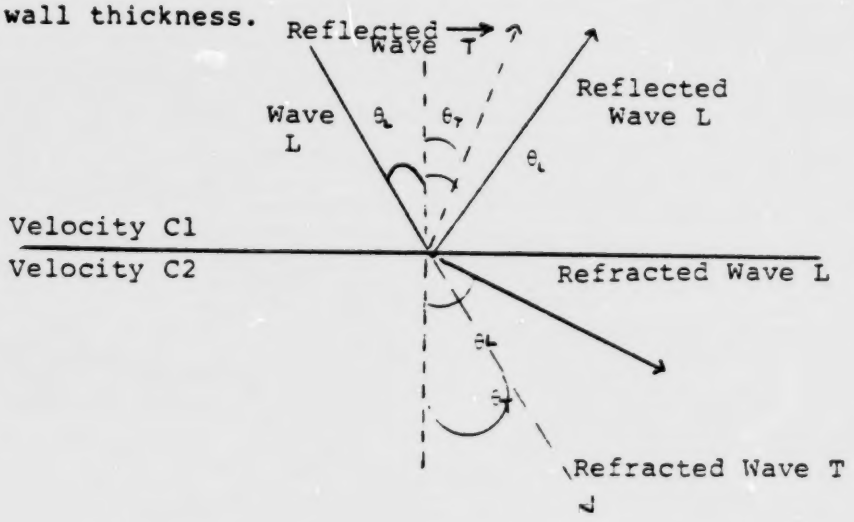

Fig. 5.1 Reflection and Refraction of an Ultrasonic Wave

When a uniform wave is inserted into a test pipe, part of the wave is reflected and part is refracted. The relation involved is shown in Figure 5.1[12].

The ultrasonic wave is produced and received by a transducer which contains a transmitter and a receiver made of piezo-electric crystal. The transmitter crystal vibrates at high frequency and generates ultrasonic waves if electrical current is applied to it. When a test pipe is in contact with the transducer, the ultrasonic wave will be transmitted, through the couplant, through the pipewall and partly reflected from the other side of the pipe wall. These reflected waves vibrate the receiver crystal, causing it to produce electrical current.

The figure below displays the ultrasonic transducer and wave action on a test pipe[13].

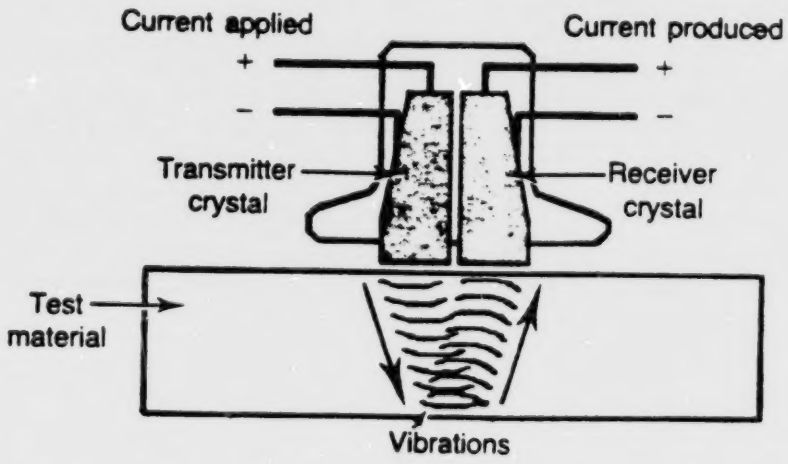

Fig. 5.2 Ultrasonic Wave Action

Before testing a pipe with an ultrasonic instrument, the nature of the test pipe must be known: wave absorption and reference pipe thickness. Travel time, when the wave is transmitted and received by a transducer, can be measured. Then, the pipe wall thickness can be determined with the travel time, propagation velocity and incident angle.

An ultrasonic instrument can be placed on a pig to measure the pipe wall thickness and detect pipe cracks from the inside [14]. The couplant between the instrument and the pipe is the fluid in the pipeline. To find cracks and defects from the outside, probes must be in direct contact with the clean surface of the pipeline at intervals of about 100 - 200 m.

Sensitivity of the method depends on surface conditions and structural properties of the pipe such as grain size, density and uniformity of good coupling between the transducer and the pipe surface. These factors affect resolution and if the resolution is not high interpretation is sometimes difficult.

Ultrasonic inspection does not affect the material being tested, and thus it is a non-destructive test method. Currently, many ultrasonic test instruments are commercially available. There is also a large amount of data and information available in industry with respect to this inspection technique.

There are some variations to the ultrasonic inspection method, depending on the processing techniques of the reflected waves. Most notable is the holographic image processing, technically referred to as Simultaneous Source - Receiver[15]. An array of transducers are used in the ultrasonic instrument and the reflected waves (both transverse and longitudinal) received by the array are processed by a computer to create three dimensional images of the test pipe material. This technique seems superior to conventional processing technique, but so far no conclusive field experience has been reported.

Advantages

- Under clean conditions, small defects can be detected;

- Accuracy of fault detection can be achieved, no matter what direction a particular crack may follow;

- Interpretation of test results can be done almost instantly by using sophisticated instruments.

- Since some ultrasonic equipment is portable, it is well suited to field test of localized pipe sections;

- Ultrasonic inspection does not interfere with operation and does not jeopardize system safety.

Disadvantages

- It is difficult to maintain good coupling between the transducer and pipe wall. It is particularly so for gas lines, in which the ultrasonic wave does not travel through gas. This remark is applicable to an ultrasonic instrument mounted on a pig;

- Interpretation of test results is more dependent on operator reliability, so that well trained operators are required;

5.3 Magnetic Flux Technique

This inspection technique utilizes the magnetic properties of the material to be examined, and thus is limited to ferritic materials such as steel. When a magnetic field is applied to ferritic materials, magnetic flux results in the materials, showing magnetic behavior. If the material is uniform, so is the magnetic flux. Distorted magnetic flux indicates defects in the materials being magnetized.

The magnetic flux is visually represented by the magnetic lines. The figure below shows the uniform and distorted magnetic flux lines, caused by materials with and without a defect.

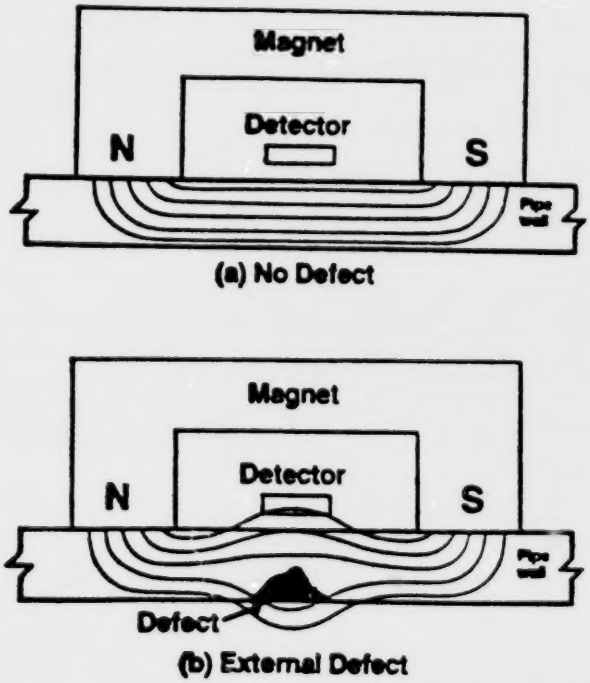

Fig. 5.3 Magnetic Flux Leakage

High pressure pipes are made of steel, which exhibits the magnetic properties different from fluid. During the course of inspection, the pipeline segment is subject to a longitudinal magnetic field. If the pipe wall is uniform, pattern of the flux lines contained in the pipe wall will be uniform. When the pipe wall contains a defect on either side of the pipe surface, the flux pattern around the defect will be disturbed. If the defect is an internal reduction in wall thickness due to gouging or corrosion, it will cause the magnetic flux to leak from the pipe wall[16]. The magnetic flux leakage occurs due to the differences in the magnetic property of the metal and the fluid occupying the defect. In turn, changes in the magnetic flux induces an electric current, which is sensed by transducers.

A series of the magnetic flux transducers are arranged in a circumferential configuration, and located between the magnetic poles. As the magnet and the transducers move along the pipeline, the flux patterns will be formed and their signals will be picked up by the transducers. The signals are amplified by an amplifier, and the amplified signals are recorded for interpretation. Since the severity of the flux change is directly related to the severity of the defect in the pipe wall, the signal will accordingly indicate the severity of the defect.

In actual applications of the technique to pipelines, the magnet and the transducers are mounted on a pigging tool. The magnetic flux pig consists of mainly three sections: a drive section, a magnetic flux detection section and a distance measuring section. The drive section is located in the front part of the pig. It basically allows the pig to be pushed by the transport medium. The magnetic detection section carries with it a magnet, transducers, a battery to power the magnet, electronics and recording devices. The function of this section is to magnetize the pipe, measure the induced current signals, process and record the signals. The distance measuring section contains an odometer to measure the distance the pig travels from a reference point.

Best known among the magnetic flux detection pigs are the AMP Tuboscope Linalog[17] and more recently the on-line inspection device developed by the British Gas Corporation [18]. It is known that the tools have been effective for detecting and locating corrosion and mechanical damages. Linalog users reported that about 95% of all the defects and approximately 80-90% of the defects detected were graded correctly. The British system is believed to have the similar capability and reliability in detecting defects due to corrosion and gouging.

The following table shows the capability of the British system, provided by Dr. Shannon, Director of On-Line Inspection Center British Gas Corporation.

TABLE 5.1

INSPECTION SYSTEM CAPABILITY

FEATURE	DETECTION SENSITIVITY	SIZING ACCURACY
Pitting Corrosion	<0.4t	±0.1t
General Corrosion	<0.2t	<±0.1t
Circumferential Gouging	<0.4t	<±0.1t
Axial Gouging	0.2t	±0.1t
Mill Damage/Repair	<0.2t	<±0.1t
Girth Weld — Metal Loss	Detected	
Girth Weld — Misalignment	Detected	
Longitudinal Weld Metal Loss	<0.2t	<±0.1t
Metal Objects Near Pipe	Detected when closer than 10 inches (size dependent)	
Casing Faults — Eccentricity	(i) Causing carrier coating damage (ii) Casing/carrier contact	
Casing Faults — Carrier Metal Loss	<0.2t	±0.1t
CP Attachments	Ferritic Attachments Detected	
Bends	Detected and Classified by Type and Angle	
Offtakes	Detected and Sized	
Valves	Detected	
Ground Anchors	Detected	
Pipe Saddles	Detected	
Location	94% of Sites within ±5ft	

t = Nominal Pipewall Thickness

Advantages

- Potential defects in a pipeline can be detected in advance reliably and located accurately (+1.5 m to +3.0 m);

- A test can be conducted without interrupting normal operations of the pipeline;

- Information on defects in a pipeline system can be stored on a permanent record. The information will be used to analyze those defects further in future tests.

Disadvantages

- Longitudinal defects cannot be confidently identified;

- Cracks may not be detected reliably;

- Interpretation of the information has to be undertaken by specialized personnel.

5.4 Acoustic Emission Technique

When placed under stress, ductile materials will omit minute pulses of elastic energy due to ductile tearing or the plastic strain of defects. This phenomenon occurs at a stress level well below its failure stress. These high frequency acoustic waves make it possible to identify those areas within a material which contains defects or discontinuities. Therefore, the structural integrity of the material under test can be determined by analyzing acoustic emission (AE) waves. A similar phenomenon has been observed in pipelines under high pressure. When a leak occurs in the pressurized pipeline, the acoustic emission waves can be the acoustic noise generated by the fluid escaping from the pipeline. This aspect is discussed in 6.1 and 6.2.

There are two assumptions regarding the acoustic emission theory[19]:

- Since ductile tearing or plastic strain increases at increasing rates as the failure stress level of the defect is approached, the acoustic activities associated with a given defect will increase as its failure stress level is approached. This effect can be used as criteria for evaluating the severity of any defects that are uncovered[20]. Most critical defects should be replaced immediately. The data on less severe defects will be

stored and later used for re-evaluation of the defects based on the criteria.

- When a defect is subject to a given stress level, it undergoes irreversible ductile tearing. In other words, once a given defect has been stressed to a given stress level, it will not subsequently produce acoustic emissions at stress level lower than the previous level (Kaiser effect). As a result of the Kaiser effect, acoustic emission monitoring must be done under conditions where the pipeline is raised to stress levels above those which it has experienced before; normally, to a level of 5 to 10% above the previous level. In an operating pipeline, this may mean having to raise the pressure level above the maximum allowable operating pressure to benefit from acoustic emission monitoring.

The AE waves propagate at high frequencies (above 100 kHz), but attenuates quickly in the steel pipe. On the other hand, the waves partly propagate at lower frequencies (about 30 kHz) and travel a few hundred meters in the pressuring fluid. The AE waves in the medium transmits its energy to the pipe wall, which is then detected by sensitive transducers. The transducers are placed against the pipe outside surface with 200 - 300 m separation along the pipeline. In addition to the transducers, acoustic emission inspection systems consist of amplifiers, to amplify the minute wave and filters to distinguish the AE waves from the background noise. A computer

processes all the data received from the array of the transducers. A typical acoustic emission analysis system is shown below.

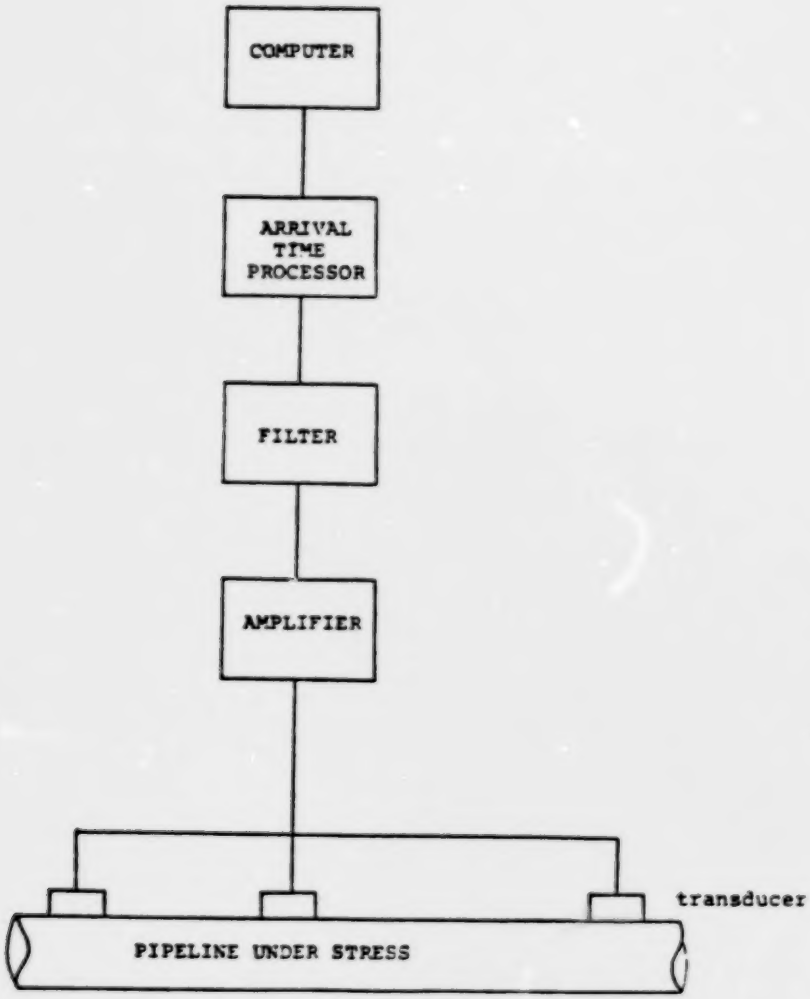

Fig. 5.4 Acoustic Emission Analysis System

The AE waves travel at the same velocity in both directions along the pipe from the wave source or defect. When the wave reaches the nearest transducer and the second transducer, the arrival time difference is calculated by the Arrival Time Processor. The distance from the defect is then computed by[21]:

$$d = (L \pm a\Delta t)/2$$

where:

d = distance from the nearest transducer to the defect
L = distance between two transducers
a = velocity of the wave in the pipe
Δt = arrival time difference

As suggested by Munk and Perry[21], AE tests can be performed by cycling internal pressure to levels of 5 to 10% above the recent operating stress. This stress level can be achieved by increasing the discharge pressures at pump stations. Since the stress cycling method offers the possibility of testing using the transport fluid and precludes interrupting the line from operation, it is particularly advantageous for buried pipeline inspection.

Attempts are still being made to find defects in pipelines through the use of the acoustic emission technique. Apparently

the technique has been successfully locating defects in certain types of piping systems, but further field evaluations will be required before the true merit and reliability can be realized.

Advantages

- The AE technique is capable of detecting the presence of serious defects to prevent them from failing well below the critical stress level;

- Location of the defects can be estimated accurately, within 5 m;

- An operating pipeline can be tested without being interrupted.

Disadvantages

- The AE technique may not be effective for detecting circumferentially oriented defects;

- Testing of long pipelines is not practical, because AE waves can travel no longer than 300 m;

- During AE testing, movement at pipe bends may occur and may cause spurious noise, which may or may not obscure results;

- Because of the Kaiser effect, this test cannot be done many times over the lifespan of the pipeline.

5.5 Visual Inspection

Visual inspection is the earliest form of leak detection [22][23]. Pipelines were walked regularly by personnel looking for evidence of leaks. This method is still used today but with slight variations. Described below are methods applicable to Arctic and off-shore pipelines.

Visual

Walking, Plane, Vehicle, Boat.

Using this method the pipeline is regularly checked by whichever travel method is practical. Oil lines can be flown by plane but it is less practical for gas lines.

Advantages

- Simple;
- Useful in locating small leaks.

Disadvantages

- High cost;
- Can only find leaks after they occur;
- Weather dependent;
- Subject to human error;

- No leak detection between inspection.

Small leaks on land or in water can be dispersed and not detected.

Aided Visual Inspection

The aided visual methods include the following:

Cameras — for offshore pipelines either remotely controlled cameras or manned submersibles with cameras are used to videotape the pipeline. Later viewing on shore can locate defects and/or leaks.

Hydrocarbon Detectors and Probes — airplanes with attached hydrocarbon detectors, these can be the electro-optical infrared type, fly the line regularly. Flame ionization sniffers can be used on shore. Underwater pipelines are checked using a launch controlled tow-fish of the infrared type.

Dogs — trained dogs have been used successfully to locate leaks in the Canadian winter environment. In one case a pipeline

company suspected a leak and the dog found a total of 40 leaks[24].

Advantages

- Better than visual alone;
- Good for small leaks;
- Helps to eliminate human error;
- Commercially available.

Disadvantages

- High cost;
- Weather dependant;
- No leak detection between inspections.

None of the visual inspection techniques described above interferes with pipeline operations.

The applicability of hydrocarbon detectors in extreme weather conditions has not been proven.

Trained animals (dogs) may prove most effective in the Arctic environment however, extremely cold or stormy weather will also impair the performance of this method.

Cathodic Protection

The amount of external corrosion of a pipeline is a function more of the soil and climate conditions than of the pipe material.

Cathodic protection properly applied and maintained is an effective means of preventing corrosion[25] [26] [27].

There are two ways of providing cathodic protection. The least costly installation is the galvonic method based on the natural battery action between the position of metals in the electrochemical table. An anode or wasting piece is deliberately used. This approach requires very careful analysis of all the varying conditions involved. The more costly cathodic protection is the impressed current method that requires an external source of electricity. The impressed current renders the piping cathodic to the surrounding soil by a controlled difference of potential.

Once the cathodic protection system has been install for off-shore pipelines it must be checked regularly. The following methods are available:

- Visual Inspections;
- Potential Readings:
  a) Using divers or submersibles;
  b) Fired monitoring units with cables to surface.

- Potential Profile Surveys:
  a) Tow-fish or trailing wire technique;
  b) Submersible/trailing wire technique;
  c) Submersible/remote reference electrode technique.
- Current Density and Electric Field Gradient Surveys.

5.6 Oil Spill Detectors at Marine Terminals

Recently detectors have been developed to detect oil spills at marine terminals and off-shore platforms. These can be broken into the following categories[28] [29] [30].

Infrared Type

Most gases are absorbed by infrared energy; infrared spectra reveal the wavelengths absorbed by a particular product and many analytical instruments employ this technique. A sample of the atmosphere is drawn into the analytical instrument and passed through a tube.

An infrared source (producing light at the wavelength absorbed by the gas to be detected) illuminates the tube and a detector at the far end of the tube determines the transmitted light. The technique is accurate and precise, and for many gases accuracies of + 1 part in 10^6 can be achieved.

The use of lasers permits the detection of gases on-line. A laser operating at the required wavelength produces a beam, which can survey the area required, and some of the infrared light is scattered from the ground onto a detector near the laser. Any gas or oil in the beam causes the signal at the detector to fail.

Bistatic Active Infrared Type

The bistatic active infrared sensor is a dual version of the monostatic type described above. A tower mounted transmitter is placed on one side of a body of water and a scanning receiver is placed on a tower on the other side. The transmitter illuminates an elongated swath between the towers and the receiver can be either fixed to monitor a small area or set to continuously scan the entire area.

A typical configuration is shown below:

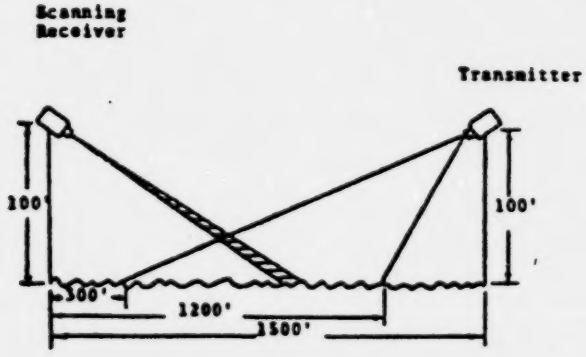

Fig. 5.5 Scanning Oil Sensor

Luminescent Type

Oil on the surface of either land or water gives off luminiscence. The luminiscence is detected by using a Fraunhofer Line Descriminater.

Fraunhofer lines are the dark absorption lines that are superposed on the continuous spectrum of the sun. By the

Fraunhofer line-depth method, intensity measurements are first made in the center of a selected Fraunhofer line, where the solar radiation has been strongly attenuated by absorption in the solar atmosphere, and are then made in the adjacent continuum. The ratio of the intensity in the center of the Fraunhofer line to the continuum intensity is compared for both radiation reflected from the target and direct solar radiation. Luminescence is indicated when the ratio in the reflected spectrum is greater than in the solar conjugate.

The instruments can be either stationary (ie. tower mounted) or mounted on a helicopter.

Advantages

Infrared Type
- Simple;
- Low to medium cost;
- Reduces dependance on visual inspection;
- Works in fog and bad weather;
- Useful at night.

Fluorescent Type
- Works well at night;
- Medium cost;
- Commercially available.

Disadvantages

Infrared Type
- Monitors only a small area (less than 1 square foot);
- Alignment difficult in rough seas;
- Requires more than one senser at terminals or platforms;
- Sensors must allow for changes in water height due to tides.

Fluorescent Type
- No daylight operation.

6.0 LEAK DETECTION METHOD

6.1 Ultrasonic Leak Detection Technique

Noise is generated by fluid leaking from a pressurized pipeline through a narrow opening. Ultrasonic leak detection methods use a noise recording device mounted on a pig, which takes advantage of the following leak noise characteristics:

- The noise appears at both audio frequencies and ultrasonic frequencies, which range from 6 kHz to 80 kHz. The general background noise, produced by fluid flow, air entrapment and the movement of the pig, also exists in the line. The background noise level is higher in the audio range than in the ultrasonic range;

- The noise amplitude generated by a leak represents the maximum signal. The amplitude sharply increases with the flow rate and the line pressure. Therefore, the leak noise cannot be observed when the flow rate and/or the pressure level is lower than a certain limit;

- The sensitivity of leak noise varies with a leak configuration. The greatest sensitivity to noise production is obtained with fine tapered holes. A smaller hole produces as much noise as a large hole even if the leak rate from the smaller hole is less;

- The leak detectability depends on the type of fluid. So far, a gas pipeline leak detector pig is not available;

- The sharp drop in noise level is observed as the leak detector pig passes the leak.

The leak detector pig is basically equipped with a hydrophone which senses acoustic energy produced by escaping fluid, an odometer to measure the distance travelled, and a recording device to provide a record of the line check. The leakage signals detected by a hydrophone are amplified and electronically filtered to remove the background noise. Correlation of the leak signal with the odometer reading pinpoints the location of the leak.

The leak detector pig works in the same way as the other type of pigs. The detector pig enters the pig launch, is carried through the pipeline by the moving fluid. The pig is also equipped with a driver to move up to higher elevations. Before it moves along the line, the onboard odometer is set at a reference point to locate the positions. While it travels with the fluid, the pig surveys the pipeline and the onboard recording device records all the signals in the pipeline.

The figure below shows a typical leakage signal picked up by the hydrophone.

Fig. 6.1 Leakage Signal

The Texaco leak detector pig[31] can operate continuously for 25 - 30 hours and AMF Tuboscope Acoustic Leak Detector[32] for 90 - 120 hours. The former was found capable of detecting leaks as small as a few liters per hour, and the latter about 20 liters an hour. It is reported that these pigs can pinpoint the leak well within 100 m.

Advantages

- The leak detector can detect extremely small leaks, and location of a leak is accurate;

- The operation is very simple and the normal operation of the pipeline is not interrupted;

- The operation can be done by non-specialist personnel. The recorded data can be easily interpreted by operating personnel.

Disadvantages

- A leak cannot be detected between the periods that the pipeline is surveyed by the leak detector.

- When a pipeline section is operated under a certain pressure a leak cannot be detected due to insufficient noise generation. This may be overcome by a temporary increase in pressure during the test. A similar problem occurs when the flow rate is too low in the line;

- So far, there is no suitable device available for gas pipelines.

6.2 Acoustic Array

Acoustic (Sonic) leak detection can be divided into active and passive methods[34] [35] [36].

Passive detection listens for the natural sound created by escaping fluid.

In the active method a known sound wave is inserted into the fluid in the main pipeline. The sound propagates down the main and escapes from the leak with the fluid.

Several methods of passive acoustic leak detection have been developed. The Institute of Gas Technology (IGT) has proposed two systems, one which uses a microphone located inside the pipeline and the other uses a probe which has a sensor that is inserted into the ground.

A Houston company CRC-Bethany International Inc. has developed a device called a Transient Pressure Wave Monitor[34].

Transient Pressure Wave Monitors are electronic systems that continuously monitor gas or liquid pipelines, and that detect, alarm and confirm the occurrence of leaks, or ruptures, in the line, and provide autonomous, station, or central control of valves to restrict or divert fluid flow whenever a leak or

rupture occurs. They can also compute and display the distance to the leak, or rupture, and the relative size of the leak.

Such Systems automatically reject pressure pulsations and spurious transient pressure waves that may be generated in the fluid by normal operations in the line which could otherwise conceal the occurrence of a leak, or rupture, or cause false alarms.

Transient Pressure Wave Monitors reliably detect the occurrence of minor or major leaks, or ruptures, at distances of 100 miles or more in gas pipelines, and 200 miles or more in crude, product and other liquid pipelines. Monitor sensitivity in any given pipeline varies directly as the square of the ratio of leak diameter to pipeline diameter, and indirectly as the square of the distance to the leak, and to the number and size of taps in the line. In gas pipelines, sensitivity also varies directly as the pressure in the line.

Typical system sensitivity may be expressed as follows:

$$Am = C \times \left(\frac{\dot{q}}{D\ d}\right)^2 Pc$$

Where:

Am = Amplitude of the transient pressure wave

C = Calibration constant dependent upon the characteristics of the fluid in the pipe

d_1 = Diameter of the leak

D = Diameter of the pipeline

d = Distance to the leak

P_c = A pressure constant

If a transient pressure wave encounters a tap or open crossover in the line, and the length of the encountered pipe is approximately 100 m or more, i.e. 1/4 wave length, the wave divides between the two lines by the following ratio:

$$\frac{dm^2}{dm^2 + dt^2}$$

Where:

dm = Diameter of the monitored line

dt = Diameter of the tap

When a leak or rupture occurs in a pipeline or vessel containing gas or liquid under pressure, a sudden decrease in fluid pressure occurs in the immediate vicinity of the leak. If line pressure is greater than approximately 40 psi, this sudden change in pressure creates a rarefaction pressure wave in the fluid. Such transient pressure waves travel at acoustic velocity through the fluid in both directions from their point or origin. Acoustic velocity in natural gas is approximately

1,300 feet (400 meters) per second and in crude oil is approximately 3,400 feet (1,040 meters) per second.

The transient pressure wave in the fluid is detected by a dynamic pressure transducer that continuously monitors the fluid in the pipeline through a 0.25 inch to 0.50 inch diameter tube tapped into the monitored line. The dynamic pressure transducer provides output signals proportional to the amplitude of the transient pressure wave travelling through the fluid, but does not respond to the static pressure in the line.

Directional Monitors, for installation at or near compressor or pump stations, utilize two (2) dynamic pressure transducers and a time delay circuit to filter out normal operating pulsations emanating from the station. If not filtered out such pulsations could mask, or conceal, the transient pressure wave generated by a small leak or rupture, and thereby prevent its detection.

Non-Directional Monitors, for mounting at locations other than compressor or pump stations, utilize only one dynamic transducer, and do not have input time delay circuits, since pulsations from any compressor or pump stations in the line will be consumed by the fluid prior to their potential arrival at the monitor site.

When the amplitude of the transient pressure wave is large enough to exceed the threshold setting of the monitor, an ALARM

condition is initiated. The alarm condition is maintained until sufficient time has elapsed for initiation of a leak confirmation condition after which it may be automatically reset, or until manually reset by a front-panel pushbutton. The amount of time delay in each case is dependent upon the length of the line, the fluid in the line, distance to the leak, and the confirmation method used. In a 60 mile liquid line, it will be 1.5 minutes or less; in a 60 mile gas line it will be 4 minutes or less.

Location of the detected leak or rupture between two monitors in the line is accurately determined and displayed. In determining the distance to the leak, or rupture, the monitors resolve the following equation:

$$d = \frac{1}{2}\left[L + a\ (t_1 - t_2)\right]$$

Where:

d = Distance to the leak or rupture

L = Distance between the nearest upstream and downstream monitors from the leak or rupture

a = Acoustic velocity through the fluid

t_1 = Relative time of detection of the wave by a first monitor

t_2 = Relative time of detection of the wave by a second monitor

Internal real-time clocks are used to determine t_1 and t_2. As an alternate, an integral counter is used to count the distance to the leak.

The primary means of confirmation is the computation of a valid distance to the detected leak. When a wave is detected by two monitors, one upstream and one downstream from the wave's originating point, and the originating point is determined by the system, or by a SCADA system, to be between the two monitors, the distance is a valid one, and the resulting output signal initiates a confirmation condition in the related monitor or monitors. Reaction time is dependent only upon acoustic velocity in the fluid, and the distance to the leak or rupture.

Two secondary means of confirmation are available. Both means are dependent upon a change in static pressure in the line, and their circuits are maintained in an inactive condition until a transient pressure wave has been detected by their related monitor. Since they are active only during an alarm condition, the static pressure monitoring circuits are not as susceptible to noise in the line as they would otherwise be. As a result they can frequently be adjusted for greater sensitivity (typically 6 psi per minute) than if they were continuously exposed to the fluid in the line. Response time with both methods is dependent upon the size of, and distance to the leak, or rupture, and upon operating conditions in the line. It will vary from a few seconds for a major rupture very near a

monitor to hours or infinity for small leaks or ruptures several miles from a monitor.

Secondary confirmation methods are:

1. Low line pressure (below a preset level);

2. Rate of line pressure drop (dp/dt) (above a preset level).

Transient pressure wave monitors are extremely sensitive to leaks. The occurrence of 1/8" diameter holes in 8" diameter gas lines and 1/16" holes on 12" liquid lines, have been detected at a distance of 10 miles from the monitor. Typically, leak flow rates of 0.25 to 0.5% of pipeline flow can be reliably detected and located by such monitors. They are applicable to both offshore and onshore pipelines even if one end of the line is inaccessible. They cannot be used, in general, if gage pressure in the monitored line is less than approximately 40 psi.

Reports from companies using the Transient Pressure Wave Monitor state that the rate of unaccountable false alarms is high and that reciprocating compressor noise is extremely damaging the detectors sensitivity.

An alternative method is to space piezo-electric transducers at approximately 150 to 300 m spacings along the pipeline. Using this method detection of stress waves resulting from the

release of energy as the crack propagates is possible. The cracks location can be determined by the times at which the various transducers "hear" the initiation of the crack.

These transducers also can sense both the impacts on the pipe from dragging anchors, etc., and the vibrations caused by the oil escaping through the crack or hole. The impacts might not cause immediate leaking, but the damage should be investigated. By timing the arrival of the impact signals at two or more sensors spaced along the pipe, the locations of the impacts can be determined.

Also, the frequency of the incoming signals would assist in determining what caused the signal, e.g., leaking oil might create a signal in the 40 kHz range; impacts might start oscillations of under 20 kHz; and developing cracks might cause signals of 100 kHz or more.

Viewed in general terms, the technique of active acoustic leak detection involves remote excitation of the fluid contained within a buried pipeline network in the form of pressure oscillations that propagate throughout the system. This alternating fluid pressure is coupled to the external soil medium either indirectly through radial displacement of the pipe walls in the case of an unperforated pipe or directly through any existing holes in the pipe walls. This acoustoelastic coupling results in the excitation of radiation in the form of both compressional and shear waves. Reflection

of these elastic waves from the surface gives rise to displacements that may be detected by means of conventional accelerometers or optically by using laser interferometry.

Theory indicates propagation of the acoustic wave in the fluid within the pipe with phase velocity Co to be accompanied by compressional and shear wave, propagating at velocities α and β respectively, in the surrounding earth medium at angles θ_c and θ_s with respect to the pipe axis, figure below.

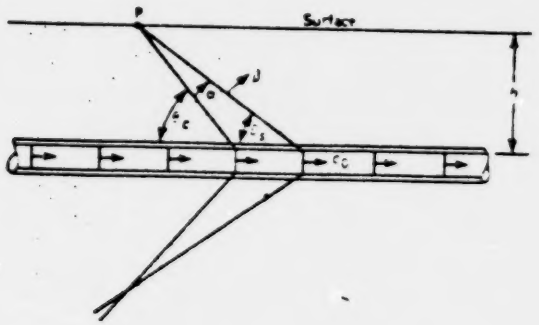

Fig. 6.2 Elastic Wave Propagation in the Earth

A diagram showing elastic wave propagation in the earth accompanying the passage of an acoustic wave in the fluid within a buried pipe. The compressional wave velocity in the surrounding earth is designated as α and that of the shear wave velocity as β.

Thus, for example, when the soil-borne compressional wave arrives at point P on the surface, the wave front within the gas has passed beyond by a distance:

$$\delta_c = h \cot \theta_c$$

where θ_c is given by:

$$\theta_c = \sin^{-1} (a/Co)$$

For the shear wave propagating with a slower velocity, Co is larger and thus the first arrival will be the compressional wave. If P is located at distance ℓ from the acoustic source, the total time required for the disturbance to arrive at P is:

$$t_A = \frac{\ell + \delta c}{Co} = \frac{\ell}{Co} + h \left[\left(\frac{1}{a}\right)^2 - \left(\frac{1}{Cc}\right)^2 \right]^{\frac{1}{2}}$$

Reliability needs to be improved if Acoustic Array technique is to be readily accpeted in the Pipeline Industry. Some expermentation is proceeding now in applying micro-processors to the current technology[35] [37].

Advantages

- In case of oil pipelines, the oil need not travel to the surface of the soil or water for inspection;

- With spaced sensors or sensors at the end of the pipe segment communicating with each other leak location accuracy is high;

- Can detect very small leaks;

- Can detect incipient leaks;

- Can detect outside third party damage;

- Continuous detection capability; and

- Relatively inexpensive.

Disadvantages

- Cannot accurately determine size of leaks;

- Reliability is not high; and

- Installed systems generate a number of false alarms.

6.3 Volumetric Method

An apparently simple method of leak detection is to measure and compare the flow-in and flow-out at both ends of a pipeline segment. Here, a pipeline segment is defined as a continuous section of pipe with inlet and outlet flow meters. If the difference between the two flow rates is larger than a preset value, then it is assumed to be caused by a leak and an alarm is set off. This method is deceptively simple in concept, but in fact requires a careful analysis of its validity.

The law of mass conversation dictates that the change rate of mass in the pipeline or line pack change is equal to the difference between the flow into and out of the pipeline segment. In other words, the following continuity equation holds in the segment:

(Flow-in) - (Flow-out) = change in line pack over a time interval

Where all these quantities are in terms of mass.

The line pack is a function of the fluid properties, pressure, temperature, pipe elasticity, pipe diameter, wall thickness, and length of the pipeline. The change in the line pack is a dynamic quantity, constantly packing and unpacking in the line because of the compressibility of the fluid. Since the compressibility of gas is much larger than that of oil, the

line pack variation is also much larger in a gas pipeline than an oil line.

One way of defining a steady-state is that the line pack does not vary with time in the pipeline segment. This implies that the right hand side of the continuity equation equals zero and thus if a steady-state is prevailing and there is no abnormality in the segment, the flow-in should be identical to the flow-out. Therefore, steady-state is a necessary condition to apply the volumetric or flow balance method. To put it differently, the method can be used only when the pipeline operates under steady-state conditions.

Flow due to a leak is not directly measurable. If a leak occurs in a pipeline segment, the flow leaking out of the segment cannot be accounted for by the continuity equation. Initially, the leak will be fed from the line pack and eventually from outside the pipe segment. If the flow is controlled at the downstream meter in the segment, the leak will be fed from the flow into the segment and thus the incoming flow will increase. On the other hand, if the flow is controlled at the upstream meter, the leak will reduce the flow out of the segment. In either case of controlling the flow, the flow-in will be larger than the flow-out for all leaks.

So far, theoretical aspects of the volumetric method have been explored. In actual applications to pipeline systems, this method has been implemented in two ways: with computers and

- Unlike the traditional volumetric method, the model can approximate the leak location on liquid pipelines.

This new technique is not without flaw. The main disadvantages are as follows:

- The method cannot detect extremely small leaks;

- The method relies on communication system heavily;

- The method cannot pinpoint the leak location, but only estimates it. Therefore, after detecting a leak, some other means such as visual inspection should be adopted to locate and correct the failure; and

- The initial costs to install the model including the SCADA system are expensive.

without. During the last decade or so, we have witnessed a large number of implementation of computer-based control systems. The systems provide the operators with reliable and versatile control capabilities. Basic requirements of automatic leak detection can be partly met by using a computer-based control system. Since the computer systems will be more cost-effective and more reliable in the future the volumetric leak detection method without computers will not be considered here. Computer-based control/leak detection systems are not alike, each has to be designed for operator's needs and specifications. But the basic approaches are similar, and thus a typical approach is described below.

The computer system collects all data available from operating sensors or remote transducers. Flows should be measured at both inlet and outlet at the same time, and as well pressure and temperature readings should be made at the same points. If the flows are read at operating conditions, the flows should be compensated for pressure and temperature to standard conditions or conditions at one end measurement point or the other. When compensation is made, the accurate fluid property should be used to get reliable values. It is recommended that flow be measured using either positive displacement (PD) or turbine meters for accurate measurement[38].

All the measurements are made by the computer system each scan. To reduce the effects of random noise in the measured values, the data values are usually averaged by using some sort

of filtering technique over several scans. These filtered values are used for calculations and comparison. When the values are read, it may be necessary to check the validity of the data and use them judiciously.

Depending on the level of sophistication, the system will include some possible logic that an operator uses to examine the pipeline integrity and detect leaks. The most sophisticated system should have a transient model built in it to accurately calculate line profiles and packing (refer to the section on mathematical modelling in this report). If such a dynamic model is not available, the line pack should be compensated either with measured pressures and temperatures in the segment or with calculated pressure and temperature profile based on the steady-state assumption. In addition to this logic, some limiting values are preset to be used as the reference values. These values are determined by calibrating the specific pipeline system under normal operating conditions.

Now, the compensated flow-in is checked against the flow-out in the segment, following the logic implemented in the computer control/leak detection system. Under normal situations, the flow deviation would be within the reference value. If the deviation falls outside of the reference value, it is considered to be unusual and a warning message is generated. The warning message has to be analyzed by the operator to confirm the possibility of a leak. If the pipeline is an oil line, the pressure will drop along the line. Such additional

information could certainly help the operator to trigger a leak alarm. Unless the flow imbalance is overwhelming, careful review of the flow response is required on the part of the operator.

The line pack would not change noticeably for short small pipelines or for lines which seldom undergo large operational fluctuations. For such lines, the volumetric leak detection method can be effective if small leaks are not of major concern. Potential errors due to physical characteristics of the fluid and the line pack in the pipeline are thoroughly discussed and shown graphically in Reference[38].

It is well known that not many pipeline systems operate always under steady-state conditions. Some factors like daily temperature variations cause extremely minor transients in the pipeline, and some like a pump shutdown or start-up cause violent transients. The transient effects are directly related to the change in line pack, whose quantity is not measurable. Thus the continuity equation cannot be reliably used, because the line pack change with time is not available.

There are several factors which have causal relationship with transients in the pipeline: temperature, product, flow rate and pressure.

Temperature

Temperature responds slowly to any disturbances in the pipeline. Seasonal, even daily temperature variations are so gradual compared to the other transients that such temperature effects on the fluid can be ignored or adjusted slowly.

If the discharge temperature at a pump station changes, however, the temperature gradient along the pipeline gradually moves to a new temperature profile and so do the fluid density and pressure profiles. In addition, the line pack will vary accordingly. This could be of the order of 1% for liquid and a higher order for gas. Such upsets in the line will last for a long period of time depending on the fluid and operating conditions. Therefore, the temperature variations would result in false alarms if its effects would not be properly accounted for in the volumetric method.

Product

The density and viscosity of each product may be different. When a product with different density and/or viscosity enters the pipeline, the pressure will be different initially near the interface between the new and existing product, and the pressure transient caused by the batch process will travel along the line. Also, density and pressure profile will vary with the new batch position along the line. Since the line pack is a direct function of the product density, the line pack

will change with time. Thus, the direct comparison of the flow-in with the flow-out would give an erroneous result. Usually, transients due to product change do not last a long time unless two products in the batch have drastically different density and viscosity. This is not the case for crude oil or natural gas pipelines.

Flow Rate

Often, the flow rate changes at delivery or take-off points. Since the flow rate is tied with pressure most sensitively, the flow changes cause more violent transients along the pipeline to establish a new pressure and velocity profile. The new pressure along the line results in a new density profile, so that the line pack would change with time. From the continuity equation, it is apparent that the flow-in cannot be identical to the flow-out during the flow ramping or flow regulation period. Therefore, the volumetric method cannot be simply applied to detect leaks until transients caused by flow ramping are attenuated.

Pressure

Pump start-up and shutdown cause pressure and flow to change dramatically. So do valve operations and station set point changes. All these types of operations induce large transients along the line. Notably, the travelling transients result in large line pack changes in the line, the degree depending on

the product compressibility. In addition, until the transients settle down, the flow-in will not be the same as the flow-out. Since the accurate pressure and density profiles are not available, the amount of fluid and its variation with time in the segment cannot be determined without a dynamic model. As a result, the volumetric method is not applicable during such operations. Figure 6.3 displays a typical flow response observed at the pump site when a pump is shut down and starts up. Figure 6.4 shows how the transients caused by the pump shutdown and start-up are responded at a downstream measurement point.

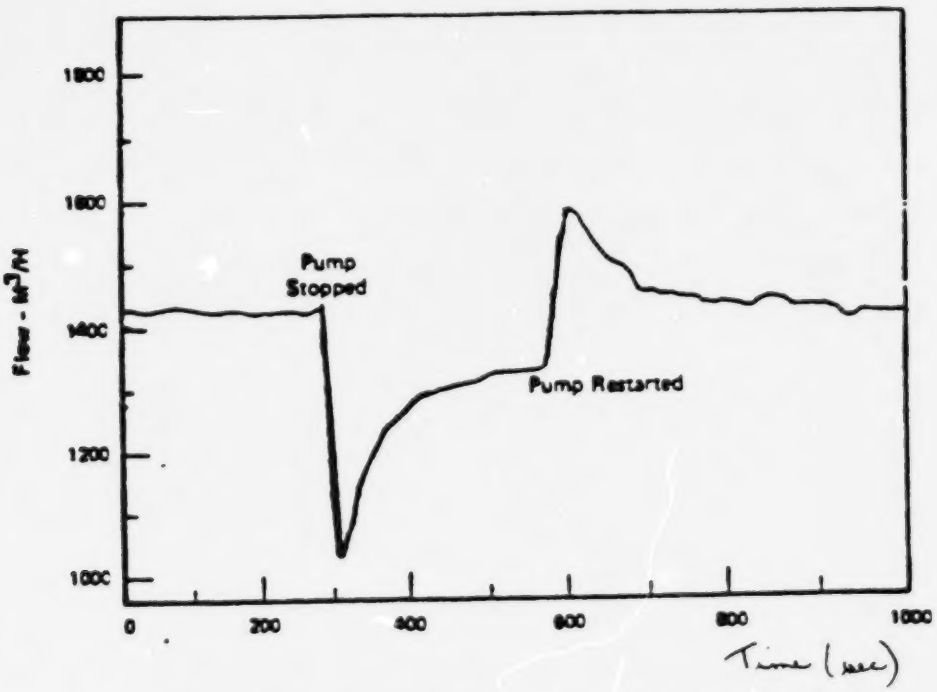

Fig. 6.3 Flow During Pump Stop and Start

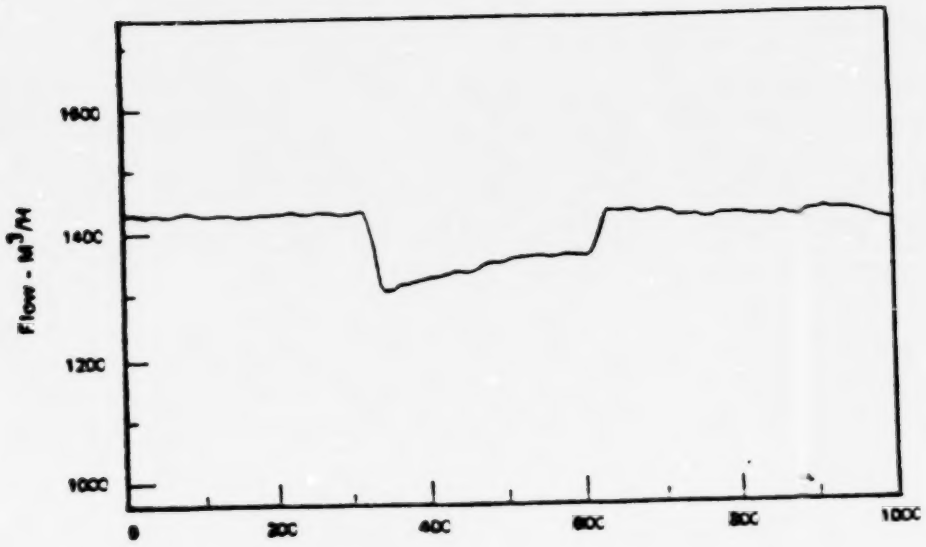

Fig. 6.4. Event of Fig. 6.3
As felt at the Upstream Pump

For longer pipelines, or for lines where operation changes are frequent, the line pack effects are so significant that the volumetric leak detection method may not work. It is even difficult to detect a leak if two meter stations are far apart from each other, because it will take a long time for leak disturbances to reach the upstream meter station.

Though not a cure-all, a computer systems must be an integral part of the pipeline control/leak detection system to check the line integrity continuously.

Advantages

- Leak detection can be practical and effective if the following conditions are met:

  i) Measurement must be accurate;
  ii) Communication equipments should always function properly;
  iii) Operational mode is kept nearly in a steady state;
  iv) There are no batches in the line.

- A computer system continuously monitors all operating data associated with the pipeline, and informs the operator of pressures, flow rates, temperatures, remote valve status and leak detection;

- It does not interrupt normal operations of the pipeline system;

- The operating costs of the leak detection system are low.

Disadvantages

- The method cannot detect extremely small leaks. If small leaks are to be detected, frequent false alarms should be expected, depending on normal operational practices.

- The method cannot locate the leak. It only indicates the leaking segment of the pipeline. After a leak is detected, a long distance is usually covered to locate the leak;

- The method relies heavily on a communication system heavily;

- The initial costs to install the SCADA system including the method will be high;

- Operational modes should be restricted to near steady states.

6.4 Negative Pressure Drop Method

The validity of this method depends on the fact that a leak causes a sudden pressure drop in the vicinity of the leak when it occurs in the pressurized pipeline. The initial pressure drop and its rate will be larger for larger leaks. As discussed in the mathematical modelling section, the pressure wave due to the leak, propagates in both directions so that the pressure drop can be observed on either side of the leak. The rate of pressure drop is higher near the leak site. However, the rate decreases with distance away from the site, and time, because of the friction and fluid compressibility. If the distance between two measurement points is short enough to measure nearly unattenuated pressure drop, the leak can be detected by using the pressure drop.

The rate of the pressure drop is usually measured by rate of pressure drop devices (ROPD). Such devices are used to detect gas line ruptures, not a leak. When excessive rates are observed, the device is activated to close control valves to stop further leakage of gas. In oil pipelines, however, this type of device is rarely used, because the pressure is so widely fluctuating under normal operating conditions that many false closures of the valves are expected. A typical ROPD is shown in Figure 6.5.

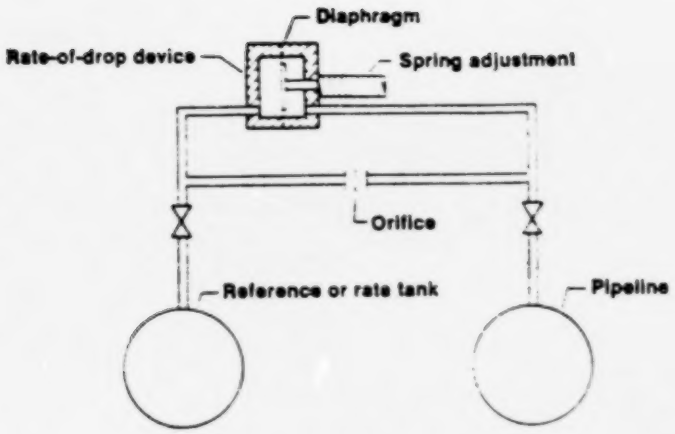

Fig. 6.5 Rate of Pressure Drop Device

The housing of the device is separated into two chambers by a diaphragm. One chamber is connected to the pipeline so that it can sense the pipeline pressure, and the other to the reference tank in which a reference pressure is maintained. The reference pressure and the pipeline pressure are balanced in steady-state through the orifice, bypassing the diaphragm. A spring attached to the diaphragm can be adjusted to set the maximum rate at which the pressure is most likely to drop during the course of the normal operations of the pipeline system. If the pressure in the pipeline drops faster than the maximum set rate, a pressure differential builds across the orifice and the diaphragm. The excessive rate of the pressure differential is assumed to be caused by a leak in the pipeline and the device activates to close control valves.

The effectiveness of such devices is a function of several factors: normal operating pressure fluctuations, block valve

spacing, pipeline configuration, flow rate, etc. Non-controllable factors with respect to the devices are leak or rupture location, size of leak and line pack conditions. As well there are aspects of preventative maintenance that if not done properly can render the device insensitive or totally inoperative. Experience indicates that this situation is generally responsible for many failures of this type of device. ROPD devices are known to be most effective, in general, for short block valve spacings (16 km or less) and for detecting complete line ruptures in a gas line.

To increase the range of a detectable pressure drop, a low pressure shutdown device is attached to ROPD and operates together. Situations often arise, where a rupture occurs but the rate of pressure drop at the sensing point is less than the set rate. Then, the low pressure shutdown device actuates to close the valves if the line pressure is lower than a preset operating minimum pressure. Effectiveness of this type of variation however is not well documented.

Rather than using a reference tank as in ROPD, the rate of flow device is arranged with the main line as shown in Figure 6.6.

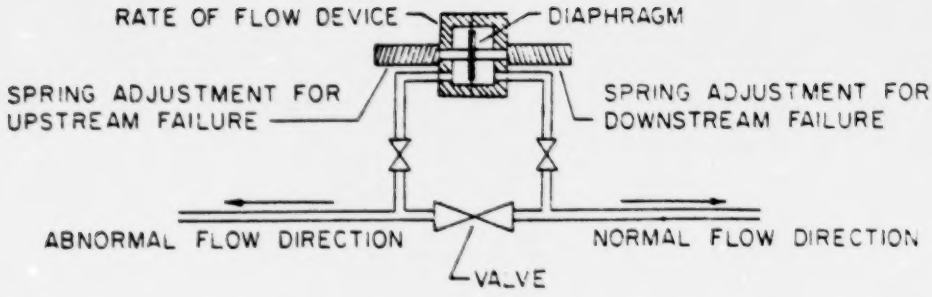

Fig. 6.6 Rate of Flow Device

The device uses some form of differential pressure cell and is preset to a certain pressure differential across the upstream and downstream of the mainline valve. When the preset differential is exceeded by an abnormal flow, the device activates and closes the mainline valve. Alternatively, direct flow metering devices can be used, and when preset alarm criteria are violated, shutdown is initiated.

Accurate setting of these devices are essential for adequate operations. The preset values should be low enough to detect a leak, yet high enough to allow normal operations without false closure of the valves. Proper settings can be achieved if changing operating conditions are fed into the computer to model the pipeline system and predict the pressure profiles.

When this type of device is installed in a pipeline system the incorporation of the followings is strongly recommended:

- A thorough study of operational conditions and the pipeline system should be conducted, so that pressure and flow response in the system are fully understood. Simulation of the system based on a transient model is most economical and results in an accurate analysis.

- Spacing between the devices should be such that preset values at the sensing points are high enough to detect it reliably.

- Establish the preset alarm criteria, which are low enough to detect a leak or rupture, yet high enough to allow normal operations without interruptions.

- Provide adequate maintenance programs to keep the devices always operative.

Advantages and Disadvantages

The advantage of this device is that it is simple in design and continuous in operation. If the device works, it quickly localizes the leak or rupture and closes valves automatically, thereby stopping the flow of gas from the unruptured segments and minimizing serious accidents caused by the leak or rupture.

However, there are several problems with this type of devices. The pressure setting is often so large that a full line rupture may fail to activate the device automatically. If the range of pressure settings is narrow, on the other hand, the lines are often interrupted by false closures under normal operations. This observation precludes possible detection of relatively small leaks. In addition, the device is difficult to operate in extremely low temperature, which is the case in the Arctic.

6.5 MATHEMATICAL MODELLING

6.5.1 Principle of Leak Detection Using Transient Model

Real-time computer applications in the pipeline environment includes modelling of the process of gas or liquid flow in the pipeline. The primary purpose of real-time computer modelling is to rapidly detect and locate leaks which may occur anywhere along the pipeline.

When a leak occurs in a pipeline, fluid is forced out of the pipeline, and as a result the pipeline pressure suddenly drops at the point of the leak. The leak then causes pressure and flow effects to propagate both upstream and downstream from the leak site. The leading edge of the pressure wave (rarefaction wave) travels in the fluid at a speed equal to the sonic velocity of the fluid. Behind this wave front the pressure slowly relaxes. For compressible fluids the leak is fed from the linepack and fluid flow changes occur more slowly than pressure. Leak rate forced through the hole is largely determined by the size of the hole and the pressure difference across the hole.

A pipeline is usually operated on flow-control at the delivery end, and on discharge pressure control at the inlet end as well as each intermediate pump station. In such a control mode, the flow will increase to compensate for the amount leaking, and the pressure at the downstream end will drop due to the

hydraulic gradient established by the friction of the flow to the pipewall. Other control modes cause different patterns of leak response, but all leaks result in pressure drop and flow change, which may be translated to leak location and size when compared with the model values.

If flow measurement points are far apart, leaks are detected by the onset and continuous drop in pressures measured at the pressure measurement points on either side of the leak. A pressure drop will initially appear at the closest point to the leak site and subsequently at points further away. The detection criteria is that the pressure drops be greater than a pressure deviation threshold at two adjacent measurement points. Initially, the pattern of larger pressure drops at two adjacent point with lesser drops further away is characteristic of a leak and discriminates against transients moving along the pipeline. The pressure in the vicinity of the leak is plotted with respect to time for a typical leak in Figure 6.7.

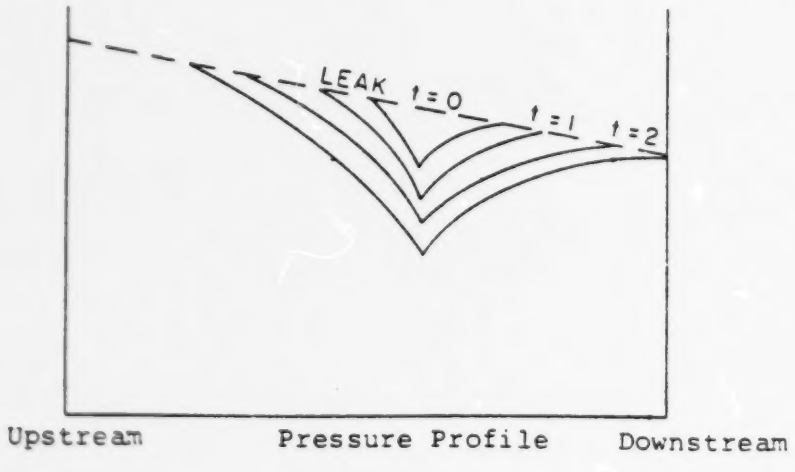

Fig. 6.7 Pressure Wave Propagation After a Leak

A typical leak pattern after time to reach a new steady state is schematically illustrated in Figure 6.8 below.

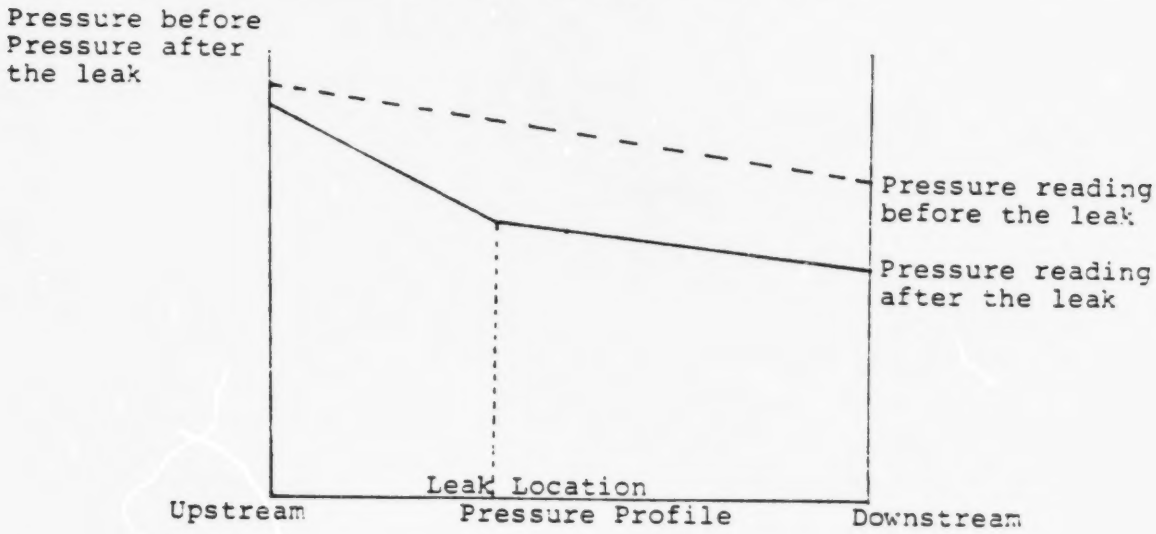

Fig. 6.8 Pressure Profiles Before and After the Leak

A real-time transient model uses only a portion of the measured field data as boundary conditions and will be unaware that the pipeline is leaking. Therefore, discrepancies will develop between the measured values and their corresponding modelled values. These discrepancies are used to detect leaks and to determine the location and size of the leaks.

The transient model is a system which simulates the current conditions in a pipeline in concert with the pipeline supervisory control system. The model performs numerical integration of the momentum equation, the continuity equation, the energy equation and the equation of state to model the pipeline using one set of field data as boundary conditions and

another set of field data for comparisons. The model compensates for pipewall expansion due to pressure, changes in elevation, product compressibility and density, temperature, heat loss, etc., so that an accurate representation of the pipeline is maintained at all times. If the pipeline is modelled accurately, normal transients such as compressor or pump starts and stops, flow changes, etc., would not cause any false alarms. A detailed discussion of the equations is given in APPENDIX I.

The following figure represents schematically a typical SCADA (Supervisory Control and Data Acquisition) system and a model interface.

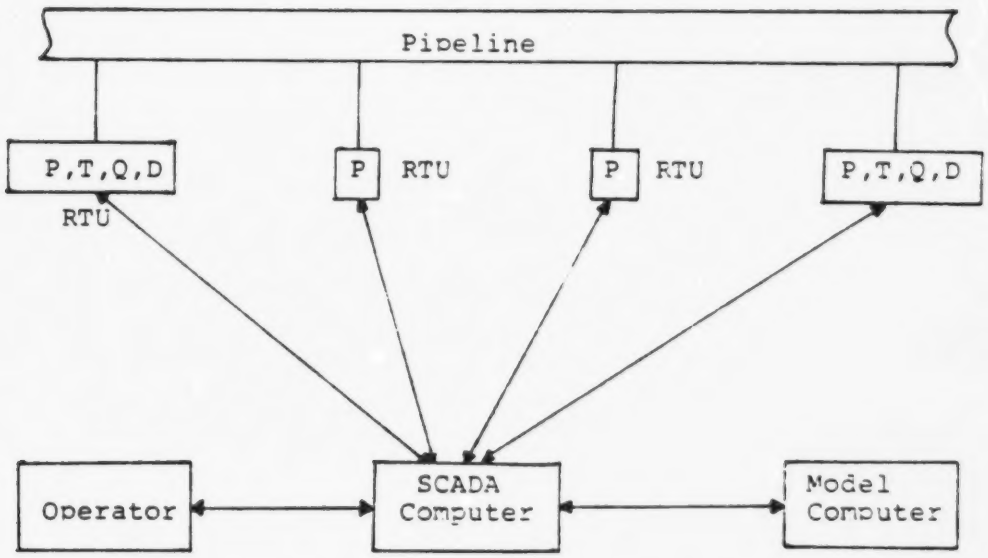

Fig. 6.9 SCADA and Model Interface

The function of the SCADA computer is to collect real-time pressures, flows, temperatures, densities, etc. in the pipeline

through RTU (Remote Terminal Unit), generate meaningful messages and reports which are fed to the pipeline operator, and facilitate control of the pipeline. The model computer receives the data on boundary conditions from the SCADA computer and calculates the pressure, temperature, velocity and density profiles. The measured and calculated values are then compared. If there is a discrepancy between the two, the leak detection module in the model suspects a leak and reports it to the SCADA computer.

There are several factors affecting the speed and accuracy of leak detection:

a) Product type in the line;
b) Leak size;
c) Flow rate in the pipeline;
d) Spacing of field measurement points;
e) Scan rate;
f) Instrument accuracy; and
g) Numerical errors associated with a model procedure.

Severe weather conditions may influence leak detection performance indirectly (ie. product property changes, instrument maintenance problem, etc.).

Product Type

The density and compressibility of the product effects the speed at which responses from the leak reach the measurement points. The magnitude of discrepancy also depends on the density. The flow response due to a leak, is delayed because the leak is fed from the available line pack.

Leak Size

Large leaks cause large pressure drops and small leaks, smaller pressure drops in the pipeline. Since the instrument accuracy is limited and pressure is attenuated, the size of the leaks can affect detection speed and location accuracy. To eliminate false alarms especially due to small leaks, a longer period of time should be allowed to observe the pressure and flow response before declaring the leak.

Flow Rate

The pressures along the pipeline are directly related to the flow rate. For higher flow rates, the pressure drops are larger and the faster pressure response is expected in case of a leak in the pipeline.

Scan Rate

Since the measured values are not continuous in time, the actual changes in the values must be approximated. The shorter the scan interval the better the resolution of the measured values. The better the measured values' resolution, the better the approximation of the behavior.

Spacing of Field Measurement Points

The disturbance due to a leak travels at the acoustic velocity of the product and attenuates as it travels along the pipeline. Therefore, the response will be detected later and be more attenuated if the measurement points are more widely spaced.

Instrument Accuracy

The model uses the measured values as boundary conditions and for comparison so instrument accuracy directly affects the accuracy of leak location.

Numerical Error

Every numerical solution procedure contains inherent error. It is proved that the error is small as long as the integration distance and time step are small. Since the model is tuned to certain measured values, the error problem can be eliminated as

long as the solution procedure is stable. The procedure stability is guaranteed by the Courant-Levy condition:[54]

$$\Delta t \leq \frac{\Delta x}{|v| + a}$$

where

Δt = integration time step

Δx = integration distance step

$|v|$ = velocity of the product

a = acoustic velocity of the product

In other words, the solution procedure remains stable and the numerical error does not grow if the Courant-Levy condition is satisfied. On the other hand, instability would result if this Δt were exceeded because the solution would progress down the pipe at a speed of $\Delta x/\Delta t$, which is faster than the physical changes propagating at the speed of sound.

Mass Balance/Imbalance

The SCADA system gathers the flow information from both the inlet and outlet of the pipeline. Since the fluid in the pipeline is compressible, the flow due to leaks is fed from the line pack initially. Because of the line pack change, material balance can not be easily and quickly proved with only the flow-in and flow-out.

The transient model provides a means for calculating the pipeline product inventory or linepack through its density and pipeline volume. This is possible through the accurate line pack calculation in the pipeline at any time. Then the flow into and out of the pipeline will be used to check the mass balance or imbalance and thus detect a potential leak in the pipeline.

The law of mass conservation states that the change in mass resident in the pipeline over a short time interval Δt is equal to the difference between the flow into and out of the pipeline. Expressing this in an equation, we have:

$$\frac{\Delta M}{\Delta t} = \frac{\Delta Min}{\Delta t} - \frac{\Delta Mout}{\Delta t}$$

or

$$\frac{\Delta Min}{\Delta t} - \frac{\Delta Mout}{\Delta t} - \frac{\Delta M}{\Delta t} = 0$$

where

$\frac{\Delta Min}{\Delta t}$ = mass flowing into the pipeline over Δt

$\frac{\Delta Mout}{\Delta t}$ = mass flowing out of the pipeline over Δt

$\frac{\Delta M}{\Delta t}$ = change in mass resident in the pipeline over Δt

The first two are measurable quantities, but the change in mass in line pack is not. The line pack is a dynamic quantity

occurring in the line and can be obtained by evaluating the following integral from the model profiles.

$$\text{Line Pack} = \int_0^L \rho(x)A(x)dx$$

where

L = length of the pipeline

$\rho(x)$ = local fluid density

$A(x)$ = local cross-sectional area of the pipeline.

The change in the line pack is simply the difference of the line packs between two scan times.

If there is no failure or leak in the pipeline, the mass balance holds because all the masses are taken into account. If there is a leak in the pipeline, however, the leaking flow is not included in the mass conservation equation so that a mass imbalance will show up:

Mass Imbalance = flow-in - flow-out - change in line pack $\neq$ 0

The non-zero mass imbalance is solely due to leaks or due to unaccountable fluid coming into the line from outside. If the mass imbalance rate is positive and the cumulative imbalance is positive for a certain period of time, then there is a leak in the pipeline. When the imbalance is in excess of an

established threshold, a leak is strongly suspected and an alarm can be safely declared.

For an offshore pipeline system, should a leak develop during flow at the line pressure lower than the outside pressure, water will flow into the line. The mass imbalance will be negative and the negative cumulative imbalance will be growing with time.

6.5.2 Leak Simulation and Analysis

6.5.2.1 Introduction

The objective of this model study is to provide the necessary framework to illustrate:

a) How the model works for a specific case;

b) How to detect and locate the leak; and

c) How the various factors affect the leak detection speed and location accuracy.

By giving examples, we can better understand the limitations and advantages of the model-oriented leak detection systems as well as design an optimum leak detection system for a given pipeline system.

The pipeline route selected for evaluation originates on Richards Island, N.W.T., and extends to Norman Wells, N.W.T., along the Mackenzie Valley route. The route traverses terrain containing permafrost, partly continuous and partly intermittent.

The climate along the pipeline route has been divided into four climatic regions for this study. Mean temperatures are

summarized in the Appendix. The pipeline map and profiles are also presented in the Appendix. The summarized data provides the basis for this simulation study and analysis. All the data used was obtained from the Canuck Engineering Ltd. data bank.

The first step in leak detection is to accurately calculate the transient pressure profile along the pipeline. Once the model is "tuned" in the field, it will use boundary conditions measured at the ends of the pipeline to simulate the real transients within the pipeline, so that the modelled pressures agree with the measured pressures along the line. In the model study presented here, the flow rate at the endpoint (delivery point) and the discharge pressures at the pump stations were used as boundary conditions. The suction pressure at each pump station is not used as boundary condition. In operation, however, the model is "tuned" to the suction pressure measurements, so that the model results agree with the measurements in the absence of a leak. An implicit assumption is that there is no leak in the pipeline during the tuning period.

6.5.2.2 Oil Pipeline

The leak detection scheme would detect the pressure drop caused by a leak. The approach used in analyzing the leak detectability is to run the case without a leak, saving the pressure profile, and then to run the same case with a leak. The differences between the pressure profiles with and without

the leak are compared. In real-time applications, these differences are the leak signals that would be seen by accurate pressure transducers operated in conjunction with a tuned model. In other words, the tuned model acts as a reference without knowing that any leak exists, while the measured data are assumed to be caused by a leak if the measured pressures are getting lower than the model pressures at the same points.

In this model study, the kilometer post, 505.2 km, was selected as a possible leak site, and three classes of leak size were considered to show the relationship between flow rate and leak size as well as the effects of various factors affecting leak detection/speed and location accuracy:
(Refer to Appendix II)

a) 1.0% and 2.0% of the average flow, 25,000 M^3/d, and of the design flow, 31,800 M^3/d (small leak);

b) 5.0% and 10.0% of the selected flows (large leak); and

c) 80.0% of the selected flows (rupture).

We use the mass flow rate, not the hole size, for leak size, because the flow rate is the representative of a true leak size.

The following kilometer posts were selected as potential pressure transmitter sites near the leak (refer to Appendix II for profile description):

Kilometer Post	Description	Instrumentation
360.0	Pump Station	Pressure, Temperature Flow, Density
409.8	Block Valve (BV1)	Pressure
464.4	Block Valve (BV2)	Pressure
522.6	Block Valve (BV3)	Pressure
571.8	Block Valve (BV4)	Pressure
640.0	Terminal	Pressure, Temperature Flow, Density

Table 6.1 shows the progression of the pressure change upstream and downstream of the leak. Here, the pressures at time zero are considered as the modelled values tuned in the field and those at non-zero time as measured values after the leak. If the instruments work perfectly, a leak alarm can be declared with confidence within 600 seconds after the leak, because:

1) The flow meter at the upstream pump station reads a higher flow rate than the model rate, and the flow rate keeps increasing with time; and

TABLE 6.1

Pressure vs. Time vs. Distance from the Leak
(1% Leak of the Average Flow, 25,000 M^3/d) at KMP 505.2 km)

Time from start of leak (sec.)	BV1 (95.4 km u/s)	BV2 (40.8 km u/s)	BV3 (17.4 km d/s)	BV4 (66.6 km d/s)	Flow at u/s Pump
0	8916	9194	6995	4907	25,028
60	8919	9194	6982	4908	25,074
120	8916	9188	6981	4907	25,075
180	8913	9187	6979	4899	25,103
240	8912	9187	6973	4898	25,114
300	8911	9184	6971	4896	25,126
360	8910	9182	6969	4890	25,136
420	8909	9182	6967	4889	25,144
480	8908	9182	6964	4887	25,150
540	8907	9180	6962	4883	25,158
600	8907	9179	6961	4882	25,165
900	8904	9177	6952	4872	25,191
1200	8903	9172	6947	4866	25,209

2) The pressures transmitted at the valves keep decreasing and the pressure gradient pattern strongly suggest the leak between BV2 and BV3.

Since no instrument works perfectly, measurement sensitivity should be taken into account. It's implication will be discussed in later sections. It is possible that a pressure transducer with 10 kPa sensitivity and a flow meter with 0.25% sensitivity may detect the 1.0% leak at BV3 in 300 seconds. At this point of time, however, the confidence level may not be high enough to declare a leak alarm, because the leak pattern is not fully developed. After 600 seconds, there is no doubt that there is a leak, most likely between BV2 and BV3.

If there is no flow meter at the upstream pump station, the confidence level will not be high in 300 seconds. Even though the evidence of the leak in 600 seconds may not be as convincing as that with the meter, the pressure pattern alone should be enough to issue a leak alarm. Since the pressure drop at a downstream point is caused primarily by the increased flow upstream of the leak (for upstream pressure/downstream flow boundary conditions), the pressure drop due to the leak would be smaller as the leak is closer to the upstream end and larger to the downstream end. If a leak is extremely small, the pressure drop may not be observed at a downstream measurement point. This problem is more obvious when a leak occurs nearer to the upstream end. Therefore, the importance

of a flow meter at the upstream end is evident to detect such small leaks.

Table 6.2 summarizes the results calculated from the simulation outputs showing the pressure and/or flow deviations produced by leaks for various conditions. Three methods were applied to determine the leak location:

a) Transient Pressure Method which is based on the pressure deviations upstream and downstream of the leak. This method is good for large leaks or line ruptures;

b) Pressure Gradient Method which is based on the upstream and downstream pressure gradients. This method is good for the pipeline on which pressure transmitters are closely located; and

c) Modified Gradient Method which is based on the flow deviation upstream and pressure drop downstream. This method is good for small leaks on the pipeline where a flow meter is at the upstream end.

TABLE 6.2

Leak Size vs. Leak Location vs. Time

Weather		Winter					Summer		
Flow		25,000 M^3/d		25,000 M^3/d			31,800 M^3/d		
Leak Size (%)	Time of Leak Alarm (min)	Predicted Location (km)	Error (km)	Time of Leak Alarm (min)	Predicted Location (km)	Error (km)	Time of Leak Alarm (min)	Predicted Location (km)	Error (km)
1.0 *	10	464.1	41.1	10	460.8	44.4	10	444.8	60.4
**	15	516.5	11.3	15	491.6	13.6	15	491.6	13.6
2.0 *	5	491.6	14.1						
**	10	503.8	1.4						
+	2	502.1	3.1						
5.0 **	2	501.3	3.9						
+	1	507.4	2.2	1	507.5	2.3	1	508.8	3.6
10. **	2	502.9	3.2	2	502.6	2.6	2	502.3	2.9
+	1	507.0	1.8	1	506.9	1.7	1	509.4	4.2
80. **	2	506.1	0.9	2	504.2	1.0	2	510.7	5.3

* Modified Gradient Method
** Gradient Method
\+ Transient Pressure Method

Note: Results on 2.0% and 5.0% leaks for the summer conditions are expected to be similar to those of respective 1.0% and 10.0% leaks.

By reviewing the table, the following conclusions can be drawn:

1) The weather condition would not effect the leak detection speed and location accuracy appreciably.

2) Compared to the small leaks, the leak detection time is shorter and the predicted leak locations are more accurate for large leaks and ruptures.

3) For the higher flow rates, the pressures along the line drop faster than those for the lower flow rates so that a leak can be detected faster. If the flow rate is too low, then the pressure drop would be too small to detect a small leak. (If flow is halved, pressure drop is only one quarter.)

Various factors influence the leak detection speed and location accuracy. Those factors are individually analyzed and summarized in the following pages.

By analyzing the results, we can draw the following conclusions:

1) The closer the measurement points, the faster the leak detection speed;

2) The closer the measurement points, the more accurate the predicted leak location for large leaks;

3) For small leaks, the outcome may not be affected. This is due to the fact that it takes a long time to confirm a leak and thus the pipeline reaches the steady state during that period; and

4) With shorter spacing, the leak alarm confidence level can be higher than that for larger spacing.

Therefore, it is advantageous to install pressure transducers relatively close in order to detect a leak quickly, reliably as well as to locate the leak accurately. In environmentally sensitive areas, it may be imperative to install them closely.

Spacing of Measurement Points

The spacing of measurement points, especially pressure measurement points, play an important role in leak detection speed and location accuracy, as well as in the level of confidence for alarming a leak. This is due to the fact that:

1) The pressure and flow responses due to a disturbance like a leak have a finite velocity;

2) Those responses are distorted less if the disturbance travels shorter distances; and

3) A unique pattern due to a leak can be better established by observing more points, so that the confidence level can be enhanced.

In this study, the average spacing of the pressure transmitters is about 50 km. If the average spacing is increased to about 100 km (by assuming there is no BV1 and BV3), the results presented in Table 6.3 are found. These results are compared with those of the shorter spacing for the winter conditions.

TABLE 6.3

Measurement Spacing Sensitivity Analysis

SPACING	50km			100 km					
				SAME TIME			SAME PRESSURE DROP		
LEAK SIZE (%)	TIME OF LEAK ALARM (MIN.)	PREDICTED LOCATION (km)	ERROR (km)	TIME OF LEAK ALARM (MIN.)	PREDICTED LOCATION (km)	ERROR (km)	TIME OF LEAK ALARM (MIN.)	PREDICTED LOCATION (km)	ERRO (km
1.0 *	10	464.1	41.1	10	464.1	41.1	10	464.1	41.
1.0 **	15	516.5	11.3	15	509.7	4.5	15	509.7	4.
10.0 +	1	507.4	2.2	1	513.3	8.1	3	513.8	8.
10.0 **	2	502.9	2.3	2	466.6	38.6	3	528.5	23.
80.0 +	1	507.0	1.8	1	512.9	7.7	3	517.9	12.
80.0 **	2	506.1	0.9	2	478.5	26.7	3	498.4	6.

* Modified Gradient Method

** Gradient Method

\+ Transient Pressure Method

++ In a rigorous sense, the gradient method is applicable if the line is in a steady state. In 15 minutes after the leak, the line is still in a transient state. As shown in Instrument Accuracy section, a small deviation from a true reading causes a large error in location accuracy for small leaks. This apparent inconsistency happens to be the case where a small deviation from a steady state causes a larger error for 50 km spacing than that for 100 km spacing.

Flow Rate Vs. Leak Detectability

The pressure gradient is roughly square-dependent of the flow rate in the pipeline. With higher flow rates, the pressure drop along the line is more significant, and thus the pressure drops more for the same size of leaks. As a result, it is expected that a leak can be detected faster for higher flow rates and on the other hand, pressure response could be negligibly small for low rates. The worst conditions would therefore exist for very low flow.

Scan Rate

The scan rate of a SCADA system is another factor determining leak detectability. For large leaks, shorter scan rate is more desirable in order to catch the pressure behavior as early as possible. For small leaks, however, the scan rate would not affect the leak performance in terms of detection time and location, because it would take a long time to observe a sizable pressure drop and declare an alarm (Refer to Table 6.1).

More importantly, the confidence level in leak detectability could be enhanced with shorter scan time, since the model can trace the leak pattern more closely.

Instrument Accuracy

Pressure and flow rates at the ends of the pipeline system are required to model the systems. The measure of pressures and/or flow rates are used to detect and locate the leak. Therefore, they must be available both upstream and downstream of the leak.

Ideally, leak location and pressure gradient can be represented schematically in the figure below.

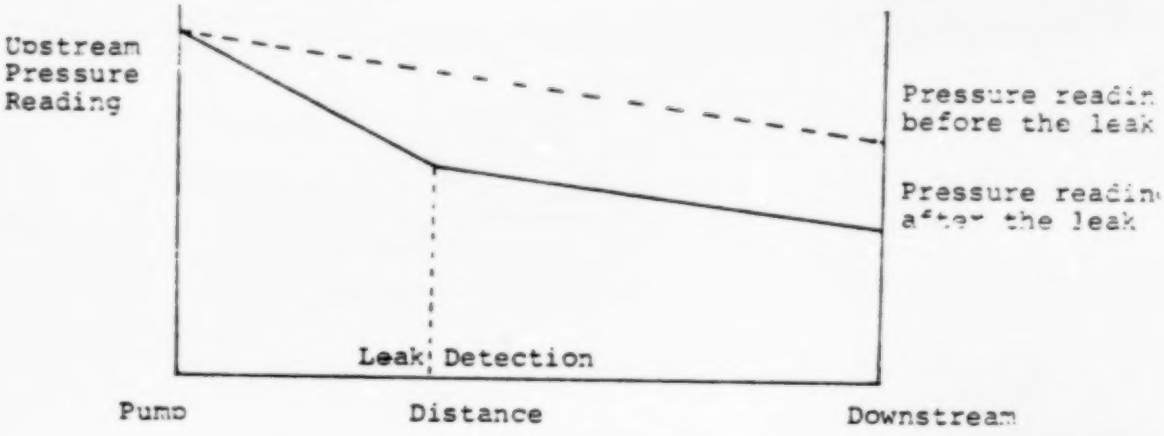

Fig. 6.10 Leak Location

This diagram simply indicates that the location of the leak can be represented as the intersection point of the two hydraulic gradients.

Since the measured values are used in the model and are compared directly with the modelled values, the availability and accuracy of the measured values are the most important factor in determining leak detectability and in locating the

leak site. Without measured values, leak detection is impossible. Here, we consider only the implications of instrument accuracy.

The accuracy of any kind of instrument is inherently limited. Therefore, the measured pressures and flows deviate to some degree from the true values. Any of these measured values could be either higher or lower than the true values. Schematically, then, the instrument inaccuracy and leak location can be shown with the following figure.

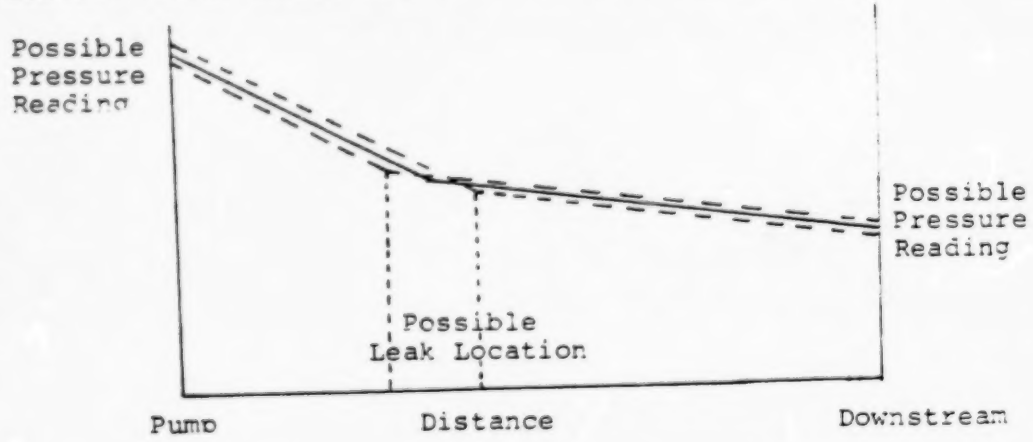

Fig. 6.11 Range of Leak Location

When the instrument accuracy is taken into account, as shown in FIG. 6.11, a possible leak can be located within the range of possible leak locations.

If the size of a leak is large, then the gradient upstream of the leak is steep and thus the range will be narrowed. On the other hand, if the size of a leak is small, the gradient

upstream of the leak is not much steeper than that downstream of the leak and thus the range will be widened.

The basic hydraulic behavior can be extended further to the relationship between the flow rate and the hydraulic gradient. For higher flow rates in the pipeline, the gradient is steep and consequently the range of possible leak locations will be narrowed. Contrarily, for lower flow rates in the pipeline, the gradient is flat and as a result the range of possible leak locations will be wide. As mentioned before, there is a flow rate under which a leak can not be detected with pressure measurements only.

Table 6.4 shows the range of possible leak locations predicted by the COV-CAN model when 10 kPa instrument repeatability is taken into account.

In the above simulation, the upstream discharge pressure is held constant. In actual operations, the measured pressures would vary in time, with measurements at the ends of the pipeline providing boundary conditions for the model. If the boundary conditions were measured inaccurately, the results would be erroneous and thus the leak detection scheme would not work properly.

Any system operating at an extremely high sensitivity must take into account possible false alarms. There are primarily two

potential sources of deviations between the measured and calculated pressures other than leaks:

TABLE 6.4

LEAK LOCATION VS. INSTRUMENT ACCURACY

LEAK SIZE (%)		TIME OF LEAK ALARM (MIN.)	PREDICTED LOCATION (km)	RANGE OF LOCATIONS (km)
1.0	*	10	464.1	431.6 - 496.6
	**	15	516.5	409.8 - 571.8
10.0	+	1	507.4	501.9 - 512.6
	**	2	502.6	492.6 - 513.4
80.0	+	1	507.0	506.5 - 507.6
	**	2	506.1	504.5 - 507.6

* Modified Gradient Method

** Gradient Method

\+ Transient Pressure Method

1) Transient errors in the pressure measurements (Constant errors are removed by model tuning and field recalibration).

2) Real transients due to change in operating parameters not taken into account.

Transient errors in the pressure measurements either affect individual sensors so that the errors can be singled out because the deviations would not be seen to propagate along the pipeline or would be produced by some general environmental effect which would cause all the sensors to deviate at once. A sensor error would not propagate in both directions in the same way as a leak transient. In general, real transients are caused by changes in pump settings, products or flow rates. Such changes must be taken into consideration in the transient model operation.

Another type of transient may occur because of changes in the pipeline parameters or environmental factors such as roughness or temperature. Such transients are normally slow and continually tuned in the model, and in any case would not produce the rapidly propagating deviations like those caused by leaks.

6.5.2.3 Gas Pipeline

As shown in the previous section, the pressure drop caused by a leak is so sensitive that the pressure is mainly used to detect and locate the leak in oil pipelines. Because of low density and high compressibility of gas, however, the pressures in gas pipelines do not drop drastically when a leak occurs, unless the leak is of rupture-size (Table 6.6). Instead, flow rate variation is much more sensitive to disturbances than the pressure variation. Therefore, the flow rate should be used as a major parameter in detecting leaks in gas pipelines.

The gas pipeline profile used here is similar to the oil pipeline, except the fact that the compressor station spacing is about 90 km. For the leak detection study three classes of leak size were induced at the kilometer post, 505.2 km: (Refer to Appendix II).

a) 1.0% of the design flow, 45.4 E6M3/D and the maximum flow of 50.0 E6M3/D (small leak);

b) 10.0% of the selected flows (large leaks); and

c) 100.0% of the selected flows (rupture).

The mass flow rate, not the hole size, for leak size was used. The approximate relationship between the hole size and the flow rate is given in Table 6.5.

TABLE 6.5
HOLE SIZE VS. LEAK FLOW RATE (E6M3/D)

Hole Size (cm) \ PRESSURE (kPa)	7,950	8,400	8,850	9,300	9,750	10,200
2.5	1.08	1.12	1.17	1.23	1.29	1.36
5.0	4.23	4.50	4.76	5.01	5.27	5.53
7.5	9.60	10.16	10.72	11.28	11.84	12.40
10.0	17.04	18.04	19.04	20.04	21.04	22.04
12.5	26.58	28.18	29.76	31.32	32.88	34.44
15.0	38.28	40.60	42.84	45.08	47.36	49.60

This table is computed on the assumption that an adiabatic process occurs and the velocity through the hole reaches the sonic velocity when a gas is being leaked from the pipeline.

The following kilometer posts were selected as potential pressure and/or meter station sites near the leak (Refer to Appendix II):

Kilometer Post	Description	Instrumentation
464.4	Compressor Station	Pressure, Temperature Flow, Density
492.2	Block Valve (BV1)	Pressure
522.6	Block Valve (BV2)	Pressure
559.6	Compressor Station	Pressure, Temperature Flow, Density

In Table 6.6, the pressure and flow changes with time are compared at both upstream and downstream compressor stations. The discharge pressures and the flow at the delivery point are used as boundary conditions, and the suction pressures at time zero are assumed to be the modelled values tuned in the field. The pressures and flow rates at non-zero time are regarded as measured values after the leak.

TABLE 6.6

PRESSURE VS. TIME VS. DISTANCE FROM THE LEAK
(100.0% Leak of the Design Flow at KMP 505.2 km)

Time From Start of Leak (Min)	Suction Pressure at u/s Comp. St.	Pressure at 13.0 km u/s (BV1)	Pressure at 17.4 km d/s (BV2)	Suction Pressure at d/s Comp. St.
0	7883	9307	8651	7783
5	7856	9348	8610	7783
10	7878	9288	8556	7780
15	7907	9236	8509	7772
20	7914	9188	8466	7760
25	7908	9145	8427	7745
30	7896	9006	8390	7726
35	7878	9071	8356	7705
40	7857	9040	8324	7682
45	7834	9012	8293	7658
50	7809	8986	8263	7633
55	7783	8962	8234	7607
60	7756	8939	8204	7580

TABLE 6.7
PRESSURE/FLOW VS. TIME

(1.0% Leak of the Design Flow at 505.2 km)

Time From Start of Leak (Min)	Upstream Compressor		Downstream Compressor	
	Suction Pressure (kPa)	Flow (E6M3/D)	Suction Pressure (kPa)	Flow (E6M3/d)
0	7883	45.537	7783	45.483
5	7882	45.724	7783	45.481
10	7883	45.470	7783	45.480
15	7883	45.492	7783	45.478
20	7883	45.519	7783	45.477
25	7883	45.544	7783	45.475
30	7883	45.567	7783	45.473
35	7882	45.587	7783	45.472
40	7882	45.604	7783	45.470
45	7882	45.620	7783	45.469
50	7881	45.633	7783	45.468
55	7881	45.645	7783	45.466
60	7881	45.656	7783	45.465

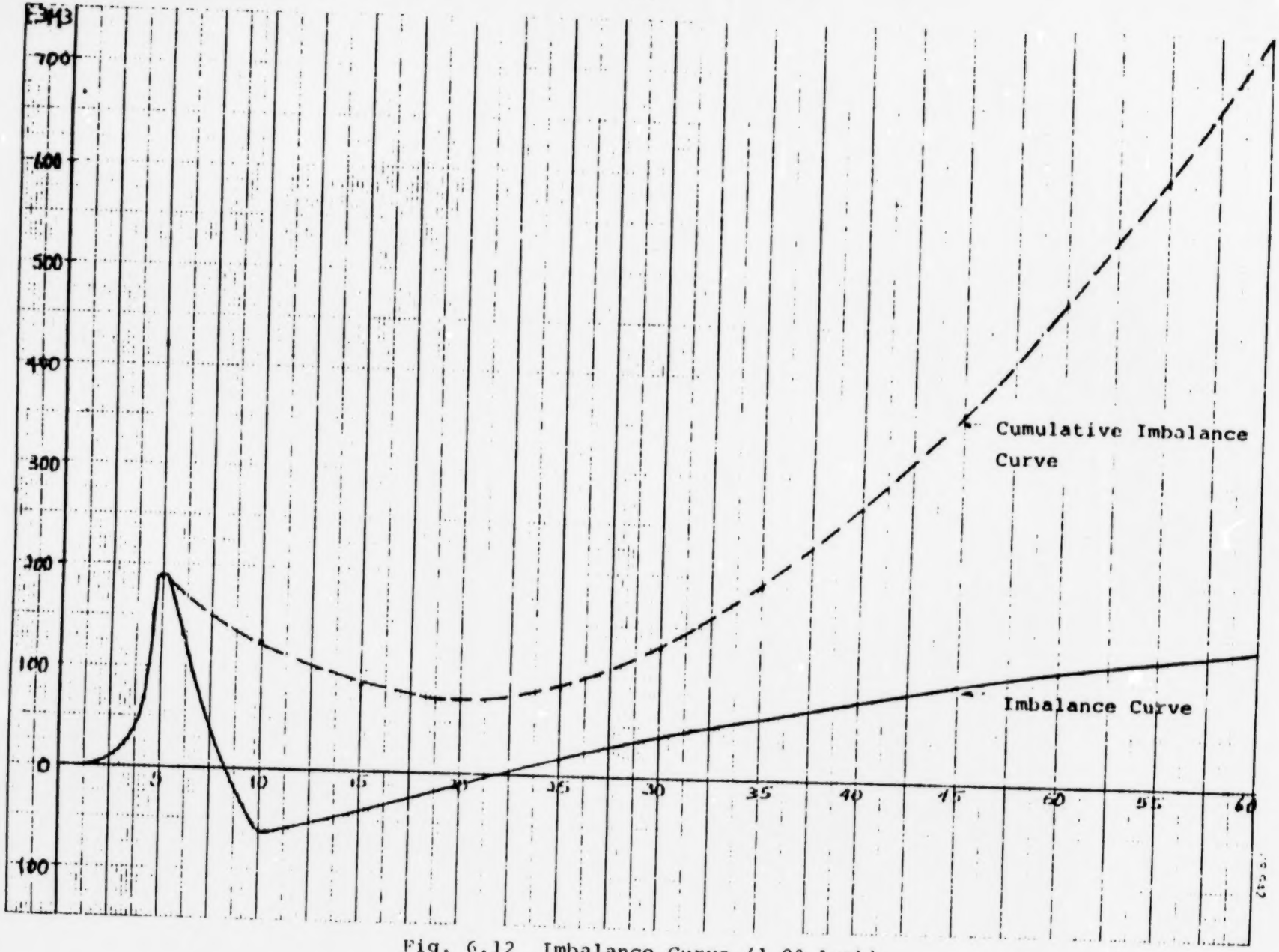

Fig. 6.12 Imbalance Curve (1.0% Leak)

As mentioned before, it is obvious from Table 6.6 that for a small leak the pressure variation is minimal and the flow change is noticeable. A flow meter with 0.25% sensitivity may be able to detect the 1.0% leak at the upstream meter station within 5 minutes. Of course, the flow change alone may not give any confidence to declare a leak alarm in such a short time period.

To increase the confidence level, the flow imbalance should be considered in a leak detection scheme. The flow imbalance is calculated using the formula given in the first section; the measured flow-in, the measured flow-out, the change in the line pack with time produced by a model.

For a small leak, the imbalance is plotted in Figure 6.12. The graph shows an increasing trend of the flow imbalance due to the leak in the pipeline. Unlike the traditional volumetric method, the flow imbalance takes into account the line pack, which causes an acute problem because of the highly compressible nature of gas. By introducing the line pack produced by a transient model, therefore, the confidence level will be enhanced and accordingly the false alarm rate can be reduced when detecting leaks, especially small leaks.

When a large amount of gas is leaking (around 10% of the line flow), as shown in Table 6.8, noticeable pressure drops are observed at the nearest pressure measurement points in 30 minutes and at the compressor stations in more than 60

minutes. Figure 6.13 shows the flow imbalance with time. With the model produced flow imbalance, a potential leak can be detected between the two flow measurement points within 5 minutes.

Unlike a liquid pipeline, there is no known method to estimate the leak location in gas pipelines. For small leaks, it is only possible to detect a leak between two flow meters confidently with a model. Large leaks can be located either between two flow meters in short time or between two nearest pressure measurements points in long time.

Like a liquid pipeline, several factors will affect the leak detectability. But most important is the accurate measurement capability of the flow, pressure and temperature measuring instruments to get reliable data and to calculate the accurate flow imbalance in case of a leak.

TABLE 6.8

PRESSURE VS. TIME VS. DISTANCE FROM THE LEAK
(10.0% Leak of the Design Flow at KMP 505.2 km)

Time From Start of Leak (Min)	Suction Pressure at u/s Comp. St. (kPa.g)	Pressure at 13.0 km u/s (BV1)	Pressure at 17.4 km d/s (BV2)	Suction Pressure at d/s Comp. St.
0	7883	9307	8651	7783
5	7880	9310	8647	7783
10	7882	9304	8642	7783
15	7885	9298	8638	7783
20	7886	9293	8634	7782
25	7885	9289	8630	7780
30	7883	9285	8627	7779
35	7880	9281	8624	7777
40	7878	9278	8621	7775
45	7875	9275	8618	7773
50	7872	9273	8615	7771
55	7869	9270	8612	7769
60	7865	9268	8610	7766

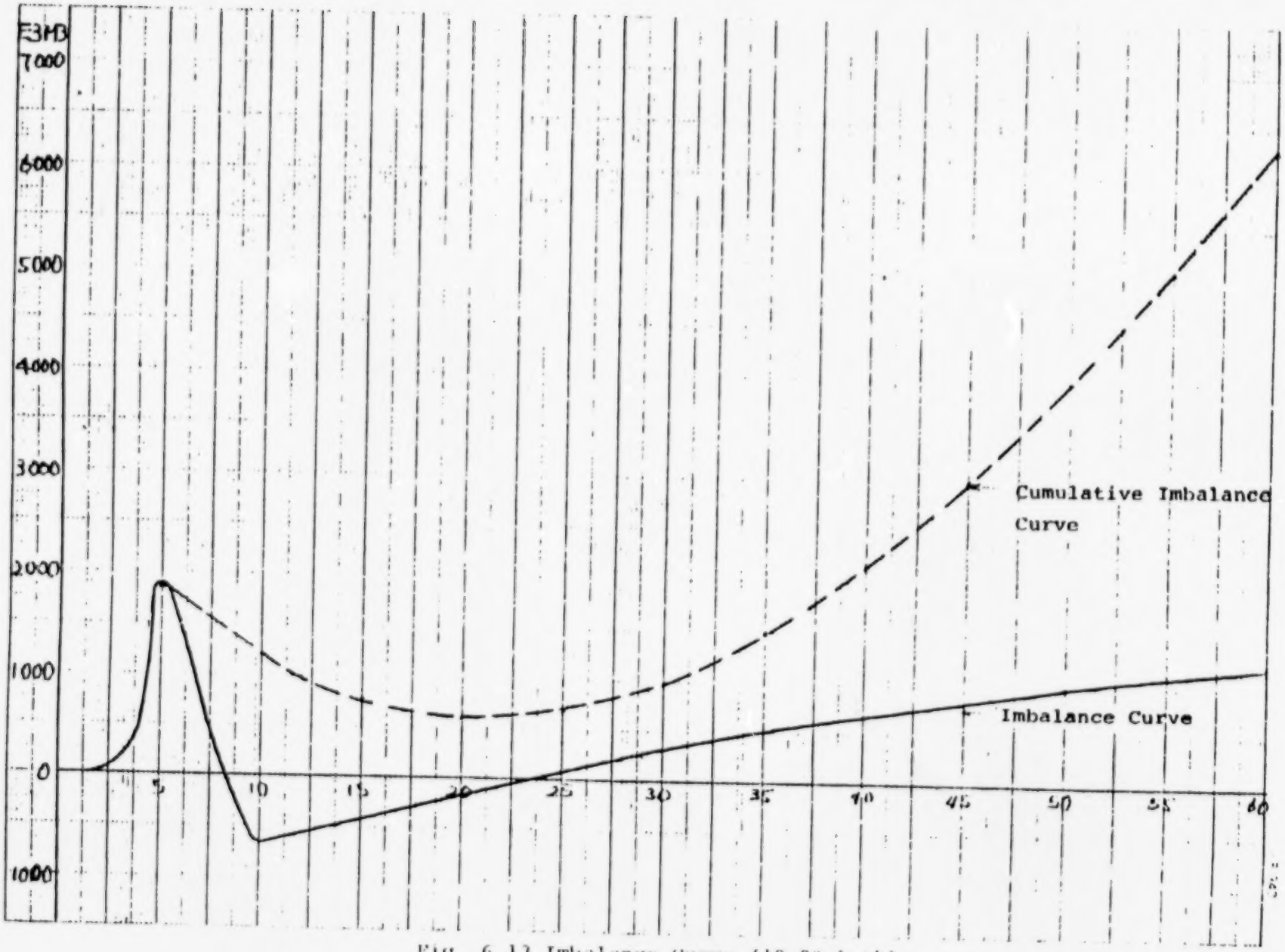

Fig. 6.13 Imbalance Curve (10.0% Leak)

The mass imbalance method using a model is an enhancement of the traditional volumetric method of leak detection. By comparing the model-produced values with the real-time data from the SCADA system, leaks can be detected in a short time and the false alarm rate will be reduced.

Advantages and Disadvantages

As discussed extensively in the previous sections, the mathematical modelling method with the SCADA system provides a new state-of-the-art technique to detect leaks. The main advantages are summarized below:

- The leak detection procedures are fully automatic. In other words, the pipeline operators do not have to analyze any data passed by the SCADA system, so that any human error can be minimized;

- The method adopts a continuous monitoring technique, if the scan interval is short. The continuous monitoring technique provides the most effective means for detecting leaks and reducing the volume of spillage;

- It does not interrupt normal operations of the pipeline system, so that the operating costs of the leak detection system are low;

- To install the detection system, the line modifications to the existing pipeline system will be minimal;

- Reliability to detect a leak is high, unless the leak is extremely small (ie. smaller than the measurement accuracy); and

7.0 CONCLUSIONS

Operational pipelines fail due to defects on the pipelines. The defect types are:

i) Pipe geometry deformations due to dents, buckles and wrinkles;

ii) Metal losses due to corrosion, gouging and spalling;

iii) Cracks due to stress corrosion, fatigue and laminations.

Pipe geometry deformations can be effectively identified by a curvature detector pig, metal losses by a magnetic flux pig, and cracks by an ultrasonic inspection pig. The acoustic emission technique is still in a developmental stage, but it shows promise as an incipient leak detection tool. The main disadvantage is that it cannot cover a long distance. The pressure testing method provides a means to check pressure - holding capability of the pipeline and determine presence of any leaks. However, it cannot locate defects and may actually accelerate crack growth.

Visual inspection confirms the leak. But the method is very costly as regular leak detection approach, and in addition it cannot be operative in the Arctic for up to nine months of the year. Although the acoustic array and negative pressure surge

technique should work well conceptually, its reliability is at present questionable in practice unless further technical advances are made. An ultrasonic leak detection pig can detect extremely small leaks and determine the leak location accurately. However, the method is not continuously operative so that it can hardly be accepted as primary leak detection method. The volumetric method enjoys a limited success, when it is implemented together with a computerized SCADA system. The main disadvantage of this approach is that it cannot detect very small leaks and may cause frequent false alarms. The mathematical modelling technique is a relatively recent leak detection method, designed for implementation in concert with the pipeline's SCADA system. This approach is basically a sophisticated version of the volumetric method, in that false alarms can be minimized by simulating the pipeline system as accurately as possible. Because of the accuracy limitation of the measuring instruments, however, extremely small leaks cannot be detected with this technique.

The most effective leak detection technique can be characterized by the following criteria:

- Detect incipient leaks and pipeline defects;

- Detect leaks rapidly. To achieve this, the leak detection system should be operated continuously;

- Detect leaks reliably;

- Declaring leaks should be as automatic as possible to minimize human error;

- Detect extremely small leaks;

- Determine the leak location accurately.

As summarized in the above, no single technique can satisfy all the criteria. Some techniques are particularly advantageous for certain situations, but some other techniques are adequate for other types of leaks. Some may be compatible techniques, which compliment each other. By integrating several compatible techniques, however, effective leak detection can be achieved. This integrated systems approach will be called a leak detection system.

8.0 RECOMMENDATIONS

The following series of recommendations is based on the criteria for the most effective leak detection system. It represents a partial list of necessary measures for the successful implementation of the system. Here, the system is viewed as an insurance policy, which is a waste of financial resources until it is needed. Therefore, it is proposed to follow a conservation approach, in that environmental protection and safe operations of the pipeline are of a prime importance.

- Pipelines should be inspected regularly by running a curvature detection pig, magnetic flux pig and ultrasonic inspection pig to keep the pipeline integrity and any defects found should be removed. Pipelines in the Arctic are advised to run those pigs twice a year; one before the winter season starts and one after;

- Employ a mathematical modelling technique in conjunction with a computerized SCADA system in order to detect leaks quickly and reliably. The technique relieves the operator's burden in declaring leak alarm;

- To find extremely small leaks and/or locate declared leaks accurately, conduct visual inspection with sensors regularly or whenever leaks are suspected. During inaccessible period in the Arctic and offshore, run an

ultrasonic leak detection pig periodically in oil pipelines. Periodic patrol will also be necessary in the Arctic and offshore pipelines;

- When technical breakthroughs are achieved, acoustic array will be helpful as a second line defense;

- Marine terminals should be inspected for oil spills using a scanning laser detection technique. Careful calibration of the instruments and backup visual inspection should be utilized as well.

A computer system should be an integral part of the on-line pipeline control and leak detection system. As well, the computer system will be used to store all the pertinent data on the pipeline system. The data will be particularly useful when the line is re-inspected in the future.

APPENDIX I

THEORY OF MATHEMATICAL MODELLING

Three basic laws and a state equation are applied to fluid in a pipe segment to obtain the differential equations for transient flow; momentum conservation, mass conservation, energy conservation and equation of state. The dependent variables are the pipeline pressure, temperature, velocity and density of the fluid. The independent variables are time and distance along the pipe measured from the upstream end.

Momentum Equation

This equation describes the motion of the fluid element and is obtained by applying Newton's second law of motion in the axial direction of the pipe.

$$\rho \frac{\partial v}{\partial t} + \frac{\partial P}{\partial x} + \rho v \frac{\partial v}{\partial x} + \rho g \frac{\partial h}{\partial x} + \frac{f \rho v|v|}{2D} = 0$$

where

ρ = density of the fluid

v = velocity of the fluid

p = pressure

f = Darcy friction factor

D = pipe inside diameter

h = elevation

x = distance

t = time

g = acceleration of gravity

The first term describes the inertia force on the fluid, and the second the surface force due to pressure. The third term arises from the kinetic energy variation, and the fourth from the potential energy. The last term is due to shear force exerted in the direction opposite to the fluid motion which is assumed to the same as if the velocity were steady.

Continuity Equation

This equation simply states that the mass in a pipe segment is conserved. The continuity equation for a compressible fluid in an elastic pipe is:

$$\frac{\rho}{A}\frac{\partial A}{\partial t} + \frac{\partial \rho}{\partial t} + \frac{\partial(\rho V)}{\partial x} = 0$$

where

A = pipe cross sectional area.

The first term deals with the elasticity of the pipe wall and its rate of deformation exerted by fluid pressure. The second term takes into account the compressibility of the fluid and the last the mass flow in and out of the pipe segment.

Energy Equation

The energy equation is an expression for the energy conservation law. The equation accounts for changes in internal energy of the fluid with changes in pressure as well as heat losses to the surroundings. Relating this concept more specifically to temperature:

$$\Delta T = \Delta T_f + \Delta T_e + \Delta T_c$$

where

ΔT = Total temperature change over pipeline segment
ΔT_f = temperature change due to isenthalpic expansion
ΔT_e = temperature change caused by elevation change
ΔT_c = temperature change due to conduction/convection

Equation of State

The equation of state is related to the property of the fluid in terms of the product density, pressure and temperature. In a liquid model, a simple linear relationship has been successfully applied:

$$\rho = \rho_o \left[1 + (P-P_o)/K - \gamma\ (T-T_o)\right]$$

where

ρ_o = density at a reference pressure Po and temperature To

ρ = density at a pressure P and temperature T

K = bulk modules of the fluid

γ = temperature expansion coefficient

There are more complicated equations of state available for a gas model such as BWRS or Lee-Kesler.

The above set of four equations is numerically solved for pressure, temperature, velocity and density with respect to position and time. There are several ways to solve the equations. The first attempt to solve the differential equations has resulted in PIPETRAN[47]. Stoner and Wylie has applied the method of characteristics[48], and Rachford et al have used Galerkin's variational method[49][50]. Wylie et al have applied an implicit technique[51] and COV-CAN an explicit form to the solution of the differential equations.

The numerical method used by COV-CAN is a finite difference scheme. The differential equations are discretized in small Δx and Δt, and the resulting equations are explicitly solved together with the equation of state. Stability of the solution is assured in the integration sequence as far as the Courant-Levy condition is satisfied.

APPENDIX II

PIPELINE PROFILE AND FLUID PROPERTIES

1.0 OIL PIPELINE DESIGN DATA AND CRITERIA

Oil Properties

The oil properties were based on a hypothetical blend of crude oil derived from preliminary field results.

-	Density	850 kg/m^3 at 15.56°C
-	Viscosity	75 CS at 0°C 34 CS at 15.56°C
-	Heat Capacity	2.2 KJ/kg
-	Pour point	-20°C
-	Bulk Modules	1,440,000 kPa

Pipeline Date

-	Total Route Length	640.0 km
-	Outer Diameter	609.6 mm
-	Wall Thickness	15.24 mm
-	Pipe Roughness	0.0254 mm
-	Depth of Cover	0.762 m
-	Soil Conductivity	1.694 w/m °C (Winter) 1.200 w/m °C (Summer)
-	Design Approach	Completely insulated

Design Criteria

- Approximate station spacings, 200 km
- Maximum operating pressure, 9930 kPa
- Maximum flowing temperature, 10°C
- Maximum flow, 35,000 M^3/D
- Design flow, 31,800 M^3/D
- Average flow, 25,000 M^3/D

Pipeline Profiles

Facility	Location (km)	Elevation (m)	Mean Temperature °C Summer	Winter
Pump	0.0	30.5	0.0	-12.2
KMP	12.8	38.1	0.0	-12.2
KMP	28.0	64.0	0.0	-12.2
KMP	41.5	15.2	0.0	-12.2
	56.2	30.5	0.0	-12.2
	72.4	30.5	0.6	- 9.4
	88.5	152.4	0.6	- 9.4
	105.9	61.0	0.6	- 9.4
	123.7	45.7	0.6	- 9.4
	144.7	213.4	0.6	- 9.4
	164.0	18.3	0.6	- 9.4
Pump	184.3	161.1	0.6	- 9.4
	203.4	256.0	0.6	- 9.4
	223.5	251.5	0.6	- 9.4
	242.8	219.5	0.6	- 9.4
	260.5	182.9	1.1	- 7.2
	279.2	274.3	1.1	- 7.2
	295.9	182.9	1.1	- 7.2
	318.3	304.8	1.1	- 7.2
	346.9	304.8	1.1	- 7.2
Pump	360.0	349.7	2.1	- 4.58
	372.5	341.4	2.1	- 4.58
	382.6	320.0	2.1	- 4.58
	396.1	304.8	2.1	- 4.58
	409.8	304.8	2.1	- 4.58
	421.4	243.8	2.1	- 4.58
	435.7	160.0	2.1	- 4.58
	453.4	213.4	2.1	- 4.58
	464.4	91.4	2.1	- 4.58
	477.4	182.9	2.1	- 4.58
	492.2	152.4	2.1	- 4.58
	505.2	121.9	2.1	- 4.58
	522.6	160.0	2.1	- 4.58
	541.1	182.9	2.1	- 4.58
	559.6	167.6	2.1	- 4.58
	571.8	243.8	2.1	- 4.58
	592.4	121.9	2.1	- 4.58
	610.4	106.7	2.1	- 4.58
	620.8	106.7	2.1	- 4.58
Delivery Pt.	640.0	114.3	2.1	- 4.58

2.0 GAS PIPELINE DESIGN DATA AND CRITERIA

Gas Composition

C1 =	94.80%
C2 =	3.47%
C3 =	0.93%
N-C4 =	0.15%
I-C4 =	0.15%
N-C5 =	0.03%
I-C5 =	0.04%
C6 =	0.01%
C7 =	0.01%
C8 =	0.03%
CO_2 =	0.26%
N_2 =	0.12%
	100.00%

Pipeline Data

- Total Route Length	640.0 km
- Outer diameter	914.4 mm
- Wall thickness	11.8 mm
- Pipe roughness	0.0254 mm
- Depth of cover	0.762 m
- Soil conductivity	1.694 w/m ^{o}C (Winter)

	1.200 w/m ^{o}C (Summer)
- Drag factor	0.975

Design Criteria

- Approximate station spacing	90 km
- Maximum operating pressure	9930 kPa
- Inlet temperature	-2^{o}C (permafrost zone /winter)
	0^{o}C (Summer)
- Maximum flow	50.0 E6M3/D
- Design flow	45.4 E6M3/D

Pipeline Profile

Facility	Location (km)	Elevation (m)	Mean Temperature °C Summer	Winter
Compressor	0.00	30.5	0.0	-12.2
KMP	12.80	38.1	0.0	-12.2
	28.00	64.0	0.0	-12.2
	41.50	15.2	0.0	-12.2
	56.20	30.5	0.0	-12.2
	72.40	30.5	0.6	- 9.4
Compressor	88.5	152.4	0.6	- 9.4
	105.9	61.0	0.6	- 9.4
	123.7	45.7	0.6	- 9.4
	144.7	213.4	0.6	- 9.4
	164.0	18.3	0.6	- 9.4
Compressor	184.3	161.1	0.6	- 9.4
	203.4	256.0	0.6	- 9.4
	223.5	251.5	0.6	- 9.4
	242.8	219.5	0.6	- 9.4
	260.5	182.9	1.1	- 7.2
Compressor	276.6	274.3	1.1	- 7.2
	295.9	182.9	1.1	- 7.2
	318.3	304.8	1.1	- 7.2
	346.9	304.8	1.1	- 7.2
Compressor	360.0	349.7	2.1	- 4.58
	372.5	341.4	2.1	- 4.58
	382.6	320.0	2.1	- 4.58
	396.1	304.8	2.1	- 4.58
	409.8	304.8	2.1	- 4.58
	421.4	243.8	2.1	- 4.58
	435.7	60.0	2.1	- 4.58
	453.4	213.4	2.1	- 4.58
Compressor	464.4	91.4	2.1	- 4.58
	477.4	182.9	2.1	- 4.58
	492.2	152.4	2.1	- 4.58
	505.2	121.9	2.1	- 4.58
	522.6	160.0	2.1	- 4.58
	541.1	182.9	2.1	- 4.58
Compressor	559.6	167.6	2.1	- 4.58
	571.8	243.8	2.1	- 4.58
	592.4	121.9	2.1	- 4.58
	610.4	106.7	2.1	- 4.58
	620.8	106.7	2.1	- 4.58
Delivery Pt.	640.0	114.3	2.1	- 4.58

APPENDIX III

ADDITIONAL BENEFITS OF MATHEMATICAL MODELLING

A mathematical model can be used as a real-time (on-line) model and/or a predictive (off-line) model. Benefits from each application are separately listed below:

a) Real Time Model

Over-pressure and Under-pressure Alarm

The model produces pressure profiles along the pipeline. When pressures at some points exceed the maximum allowable operating pressures (MAOP), the over-pressures are reported at the location. Likewise, when pressures at some point go below the least allowable operating pressure (LAOP), the under-pressures are detected at the location. MAOP violations should be avoided for safe operation of the pipeline. LAOP is particularly an important parameter for volatile liquid to avoid the risk of going below the bubble point of the product.

Pipeline Efficiency

If friction factor is much larger than it should be when the model pressures are tuned to the measured pressures, then pipeline efficiency must be lower than it should be. By monitoring the efficiency, it can be determined that pigging of the pipeline is required.

Batch Tracking

When multiple products are transported in batch, the model can track the batch movement, so that the location and diffusion profile of each product can be determined.

Optimum Operation of Pump/Compressor

Even when a load in the line is fluctuating, it is possible to determine optimum set points to operate pumps or compressors most efficiently by accurately predicting the load by the model.

Pig Tracking

The movement and location of pigs can be tracked along the pipeline, based on the modeled local velocity and the pig slippage factor. Then time of arrival at the pig receiver can be estimated.

Instrument Drift Analysis

Pipeline tuning attempts to modify the roughness and heat loss coefficient to permit the model calculated pressures and temperatures to match SCADA measured values. This is a slow process so that when an instrument goes out of calibration it won't agree with the model and can be determined to be in error.

b) Predictive Model

Design Optimization

By correctly analyzing the load characteristics and line constraints the predictive model helps the pipeline engineers design and operate the pipeline system optimally.

Usually, a steady-state model is not adequate enough to analyze the load servicebility of the transmission system when the load is to be increased.

Operator Training

Operator training has been a slow process. A transient model can show the responses to various operating conditions including unexpected upsets. Thereby, inexperienced operators can easily obtain a feel for the pipeline control modes.

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